DRAFT Report: Graphics and other information will be enhanced in Final Report.

DRAFT

Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events

Prepared for the South Carolina Office of Regulatory Staff by

Guidehouse

Guidehouse Inc.
2941 Fairview Park Drive, Suite 501
Falls Church, VA 22042

Reference No. 218522

Table of Contents

1 Executive Summary

Following the February 2021 winter storm that left nearly seventy percent (70%) of Texans without electrical power and nearly half the State without running water,[1] South Carolina Governor Henry McMaster called for a comprehensive review of South Carolina's public and private power grid. The South Carolina Office of Regulatory Staff (ORS) subsequently filed a motion with the Public Service Commission of South Carolina (Commission) in Docket No. 2021-66-A to solicit information from the State's utilities on the matter[2] and commissioned Guidehouse, Inc. (Guidehouse) to support a corresponding review. ORS provides this DRAFT Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events, in response to Governor McMaster's request. This DRAFT Report is designed to communicate preliminary findings related to the South Carolina power grid review based on initial input provided by Utility Providers supplemented by a set of key assumptions. The Final Report, scheduled to be issued by December 31, 2021, will communicate findings that incorporate input provided by Utility Providers related to ORS information requests issued after August 31, 2021, and additional assessment information.

Scope

ORS, supported by Guidehouse, examined information and evaluations provided by electric and natural gas utility providers (Utility Providers) under the jurisdiction of the Commission and other electric and gas non-regulated utilities that willingly participated in the review. The information requested from utilities providers primarily targeted eight (8) general assessment areas:

- Identification of threats to utility service
- Identification of the impacts to utility service
- Assessment of vulnerabilities
- Assessment of risks to utility service
- Identification of resiliency solutions
- Identification of other federal and state reliability requirements
- Assessment of current utility processes and systems to withstand potential ice storms and other winter weather conditions
- Identification of best practices, lessons learned and challenges to utility service

Approximately sixty-five (65) utility providers participated in the ORS Review, and four (4) non-utility stakeholders expressed documented interest in the review, for a total of sixty-nine (69) respondents.

---

[1] Watson, K., *The Winter Storm of 2021*, University of Texas Hobby School of Public Affairs, March 29, 2021, https://uh.edu/hobby/winter2021/storm.pdf

[2] *South Carolina Office of Regulatory Staff's Motion to Solicit Comments from Utilities and Other Interested Stakeholders Regarding Measures to Be Taken to Mitigate Impact of Threats to Safe and Reliable Utility Service*, Docket No. 2021-66-A, https://dms.psc.sc.gov/Attachments/Matter/76c44b6b-54d4-421e-8fd5-69bc5a24fd8f

Approach

To review the Utility Provider information and evaluations, Guidehouse professionals (Evaluators), on behalf of ORS, applied a Utility Adverse Weather Assessment Framework (Assessment Framework) adapted specifically for winter weather events. This Assessment Framework enabled Evaluators to assess utilities across eleven (11) indicator areas and five (5) categories to identify the stage of maturity for each Utility Provider by indicator area.

Evaluators clustered the Utility Providers into four (4) assessment groups based on the general sizes and services provided.

- Large investor-owned or state-owned electric utilities (LEUs)
- Large investor-owned natural gas utilities (LGUs)
- Smaller electric municipal departments, boards, or commissions or customer-owned electric cooperatives (SEUs)
- Smaller natural gas municipal departments, boards, or commissions (SGUs)

The Preliminary findings and resulting recommendations from this review are consolidated by utility provider type (natural gas and electric utilities) and utility size (large utilities and smaller utilities), as described above.

Preliminary Findings and Recommendations

The review's preliminary findings and resulting recommendations are consolidated by utility type (natural gas and electric utilities) and utility size (large utilities and smaller utilities).

Notably, the large utilities (LEU and LGU) have the greatest risk on the winter weather resiliency of the South Carolina power grid and their ability to withstand winter weather events. This preliminary finding reflects the dominance of electric power use in heating across the State during the winter season and the growth of natural gas as a fuel source in the electric power sector. SEUs and SGUs, while vital to the communities they serve, pose a much lower risk to the statewide infrastructure should they experience localized failures within their systems. A transmission line outage for an LEU carries the potential to cause additional outages on another part of the transmission system under certain high-power usage or limited power supply conditions. This risk is exponentially lower for distribution infrastructure failures at SEUs or SGUs.

Based on the preliminary review, the South Carolina power system appears to be adequately prepared to prevent and withstand prolonged outages caused by ice storms and winter weather events. Final assessment of South Carolina's ability to withstand potential ice storms and other winter weather events will be provided in the Final Report.

2 Glossary of Terms and Acronyms

AMI – Advanced Metering Infrastructure
ACSR – Aluminum Conductor Steel Reinforced
ADMS – Advanced Distribution Management System
AGA – American Gas Association
AMR – Automatic Metering Reading
APGA – American Public Gas Association
APPA – American Public Power Association
ATC – Available Transfer Capacity
BA – Balancing Area
BAA – Balancing Area Authority
BAL – Resource and Demand Balancing
BCF – Billion Cubic Feet
BES – Bulk Electric System
BPS – Bulk Power System
BTU – British Thermal Unit
CAPEX – Capital Expenditures
CHP – Combined Heat and Power
CIS – Customer Information System
CMMI – Capability Maturity Model Integration
CNG – Compressed Natural Gas
CPGA – Carolinas Public Gas Association
CPW – Commission of Public Works
CT – Combustion Turbine
DA – Distribution Automation
DCGT – Dominion Carolina Gas Transmission
DEC – Duke Energy Carolinas, LLC
DEP – Duke Energy Progress, LLC
DER – Distributed Energy Resources
DESC – Dominion Energy South Carolina, Inc.
DIMP – Distribution Integrity Management Program
DSM – Demand Side Management
ECSC – Electric Cooperatives of South Carolina
EEI – Edison Electric Institute
EHS – Environmental, Health, and Safety
EIA – Energy Information Administration
EM&V – Evaluation, Measurement, and Verification
EOP – Emergency Operating Procedure
ERCOT – Electric Reliability Council of Texas
ERP – Emergency Restoration Plans
ESF-12 – Emergency Support Function Twelve
FCI – Fault Current Indicator
FERC – Federal Energy Regulatory Commission
GIS – Geographic Information System
GLMA – Great Lakes Mutual Assistance
GRU – Gainesville Regional Utilities
GWh – Gigawatt-Hours
H&R – Hardening and Resiliency
IC – Incident Commander
ICAM – Integrity Compliance Activity Manager
ICS – Incident Command System
IEEE – Institute of Electrical and Electronics Engineers
IOUs – Investor-Owned Utilities
IRC – International Residential Code
IROLs – Interconnection Reliability Operating Limits
IRP – Integrated Resource Plan
JEA – Jacksonville Electric Authority
KMS – Knowledge Management System
kV – Kilovolts
kW – Kilowatt
kWh – Kilowatt-Hour
LDC – Natural gas distribution company
LDF – Leak, Damage, Failure
LEU – Large investor-owned or state-owned electric utility
LGU – Large investor-owned natural gas utility
LNG – Liquefied Natural Gas
Lockhart – Lockhart Power Company
MED – Major Event Day(s)
MMA – Mutual Assistance Organizations
MW – Megawatt
MWh – Megawatt-Hour
NERC – North American Electric Reliability Corporation
NESC – National Electrical Safety Code
NOC – Network Operations Center
NGA – Natural Gas Authorities
NGBU – Piedmont Natural Gas Business Unit
NOAA – National Oceanic and Atmospheric Administration
NRC – Nuclear Regulatory Commission
NSF – National Science Foundation
NWS – National Weather Service
OMS – Outage Management System
ORS – South Carolina Office of Regulatory Staff
OUC – Orlando Utilities Commission
PHMSA – Pipeline and Hazardous Materials Safety Administration

PMPA – Piedmont Municipal Power Agency
PNG – Piedmont Natural Gas Company
POD – Point of Delivery
POR – Point of Receipt
PPA – Power Purchase Agreements
PSC – Public Service Commission of South Carolina
PSI – Pounds per Square Inch
PURPA – Public Utility Regulatory Policies Act
RC – Reliability Coordinator
RMAGs – Regional Mutual Assistance Groups
RRS – Reliability Review Subcommittee
RTCA – Real-Time Contingency Assessment
RUS – Rural Utility Service
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
Santee Cooper – South Carolina Public Service Authority
SCADA – Supervisory Control and Data Acquisition (electric)
SCAMPS – South Carolina Association of Municipal Power Systems
SCPGA – South Carolina Propane Gas Association
SEE – Southeastern Electric Exchange
SEOC – State Emergency Operations Center
SERC – Southeastern Reliability Corporation
SEU – Smaller electric municipal department, board, or commission- or customer-owned electric cooperative
SGA – Southern Gas Association
SGU – Smaller natural gas municipal department, board, or commission
SNG – Southern Natural Gas
SOG – Self-optimizing Grid
SOL – System Operating Limit
SPIA – Sperry-Piltz Ice Accumulation Index
STEP – Spare Transformer Equipment Program
T&D – Transmission and Distribution
TIMP – Transmission Integrity Management Program
TPI – Transmission Plan
TOP – Transmission Operating Procedure
Transco – Transcontinental Pipeline
TUG – Targeted Undergrounding
USDA RUS – U.S. Department of Agriculture Rural Utility Service
USDOT – US Department of Transportation
VACAR – The Virginia-Carolinas sub region within the North American Electric Reliability Corporation's (NERC) SERC Reliability Corporation (SERC)
VER – Variable Energy Resources
VRA – Vulnerability and Risk Assessment
VRSG – VACAR Reserve Sharing Group

3 Background and Overview

Following the February 2021 winter storm that left nearly seventy percent (70%) of Texans without electrical power and nearly half the State without running water,[1] South Carolina Governor Henry McMaster called for a comprehensive review of South Carolina's public and private power grid. The South Carolina Office of Regulatory Staff (ORS) subsequently filed a motion with the Public Service Commission of South Carolina (Commission) in Docket No. 2021-66-A to solicit information from the State's utilities on the matter[2] and commissioned Guidehouse, Inc. (Guidehouse) to support a corresponding review. ORS provides this DRAFT Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events, in response to Governor McMaster's request. This DRAFT Report is designed to communicate preliminary findings related to the South Carolina power grid review based on initial input provided by Utility Providers supplemented by a set of key assumptions. The Final Report, scheduled to be issued by December 31, 2021, will communicate findings that incorporate input provided by Utility Providers related to ORS information requests issued after August 31, 2021, and additional assessment information.

South Carolina is home to more than five million residents and over 110,000 establishments that rely on the reliable energy delivery services of the State's more than sixty (60) distribution utilities.[3,4] While South Carolina's southeast coastal location makes its power grid more susceptible to tropical weather and climate events such as hurricanes and coastal flooding, South Carolina communities are not precluded from the impacts of ice storms and other winter weather events. The most recent example of such an event is the Winter Storm of January 2018, which produced record levels of snowfall across the southeast areas of the State and a record-setting duration of snow cover in Charleston.[5]

However, few as they may be, winter weather events affect communities ill-equipped to mitigate or recover from ice, snow, or cold weather events, and can be as devastating as a major tropical weather event. A recent study on extreme winter weather changes in the U.S., funded by the National Science Foundation (NSF) and published in *Science*, revealed that the major winter storm that led to the collapse of the Texas energy infrastructure in early 2021 was not only deadly—resulting in over 200 deaths across the State—but also unexpectedly expensive.[6] NSF noted that this mid-February Texas polar vortex "could make it the state's costliest natural

---

[3] U.S. Census Bureau, https://data.census.gov/cedsci/map?q=CBP2019.CB1900CBP&g=0400000US45&tid=CBP2019.CB1900CBP&mode=customize&vintage=2019&nkd=n~00,LFO~001,EMPSZES~001&cid=ESTAB

[4] South Carolina State Energy Plan, http://www.energy.sc.gov/files/Energy%20Plan%2003.02.2018.pdf

[5] National Weather Service, https://www.weather.gov/chs/events

[6] Texas Department of State Health Services, https://www.dshs.state.tx.us/news/updates.shtm#wn

disaster, even more so than previous hurricanes and at least twice as costly as the entire record-breaking North Atlantic 2020 hurricane season."[7]

3.1 Need for a Comprehensive Review

Governor Henry McMaster requested ORS undertake a comprehensive review of South Carolina's public and private power grid to evaluate its ability to withstand potential ice storms and other dangerous winter weather. In response to Governor McMaster's request, ORS filed a motion with the Commission requesting it call for all electric and natural gas utilities provide information regarding measures that have been or will be taken to:

- Mitigate the negative impacts of ice storms and other dangerous weather conditions on the provision of safe and reliable utility service.
- Ensure peak customer demands on the utility system can be met during extreme weather scenarios.[8]

On March 10, 2021, the Commission issued an order opening the requested docket and encouraging comments from interested parties.[9]

In June, the Commission accepted two sets of comments from fourteen (14) stakeholders: initial comments requested by June 11, 2021, and responsive comments requested by June 25, 2021. Concurrent with the Commission's solicitation for comments, ORS issued information requests to utilities and municipalities across the State to launch its comprehensive review.

This DRAFT Report is designed to communicate preliminary findings related to the South Carolina power grid review based on initial input provided by Utility Providers supplemented by a set of key assumptions. The Final Report, scheduled to be issued by December 31, 2021, will communicate findings that incorporate input provided by Utility Providers related to ORS information requests issued after August 31, 2021, and additional assessment information.

3.2 Focus of the ORS Review

ORS Review and corresponding requests for information issued to the State's Utility Providers primarily focused on eight (8) key assessment areas:

---

[7] Cohen et al, Linking Arctic variability and change with extreme winter weather in the United States, https://www.science.org/doi/10.1126/science.abi9167

[8] *Motion to Solicit Comments from Utilities and Other Interested Stakeholders Regarding Measures to Be Taken to Mitigate Impact of Threats to Safe and Reliable Utility Service*, filed February 22, 2021. https://dms.psc.sc.gov/Attachments/Matter/76c44b6b-54d4-421e-8fd5-69bc5a24fd8f

[9] *Order Establishing Docket and Guidelines for Comments by Utilities and Other Interested Stakeholders Regarding Mitigation of Impact of Threats to Safe and Reliable Utility Service*, Order No. 2021-163 (March 10, 2021). https://dms.psc.sc.gov/Attachments/Order/8d8edae0-b911-4023-9263-795302fcb218

- **Threats to utility service:** Identify and assess potential threats to the utility system, where threats are anything that may destroy, damage, or disrupt utility service.
- **Impacts to utility service:** Assess the impacts the potential threats may have on utility processes, systems, infrastructure, and end-user customers.
- **Vulnerabilities:** Assess winter weather-related vulnerabilities and the degree to which utility systems and infrastructure may be impacted and where vulnerabilities are weaknesses within utility systems, processes, or infrastructure.
- **Risks to utility service:** Evaluate the potential for loss, damage, or destruction of key assets and resources, as well as factors that could limit the supply of generation over an extended period of extreme weather conditions for each of the State's generation sources.
- **Resiliency solutions:** Measures in place or planned to enable the utility to anticipate, prepare for, adapt to, withstand, respond to, and recover quickly from winter weather-related service disruptions.
- **Reliability requirements:** Identify applicable or observed federal, state, or local reliability and resilience requirements (including, but not limited to, joint reliability plans or assessments, coordinating agreements, and wholesale purchase agreements).
- **Current utility measures:** Identify processes and systems in place to withstand potential ice storms and other winter weather conditions, processes used to determine utility preparedness for meeting peak customer demand under extreme scenarios, and steps taken to address any identified areas of improvement.
- **Leading practices and lessons learned:** Identify leading practice information related to reliability, lessons learned from similar experiences, and challenges to the provision of safe and reliable utility service under extreme weather conditions and other threats.

3.3 Participating Utilities and Other Interested Stakeholders

ORS focused the South Carolina power grid Review on electric and natural gas Utility Providers under the jurisdiction of the Commission and other electric and gas non-regulated utilities that willingly participated.

A total of sixty-five (65) of the State's utility providers participated in the ORS Review, either by submitting comments to the docket or providing responses to ORS information requests. More than half of the respondents (primarily small electric cooperatives or commissions of public works) participated through associations or other representative organizations.

Responding organizations included the following:

Individual Utility Respondents

- Bamberg Board of Public Works
- Central Electric Power
- City of Union
- Clinton Newberry Natural Gas Authority
- Duke Energy Carolinas, LLC (DEC)
- Duke Energy Progress, LLC (DEP)
- Dominion Energy South Carolina, Inc. (DESC)
- Fort Hill Natural Gas Authority
- Gaffney Board of Public Works
- Greenwood Commission of Public Works
- Greer Commission of Public Works
- Laurens Commission
- Lockhart Power Company (Lockhart)
- Marlboro and Pee Dee Electric Cooperatives
- McCormick Commission of Public Works
- Orangeburg Dept of Public Works
- Piedmont Natural Gas
- Santee Cooper

Utility Representative Respondents

- Electric Cooperatives of South Carolina (ECSC) (responding for eighteen (18) electric cooperatives)
- Patriots Energy Group (responding for three (3) natural gas authorities)
- Piedmont Municipal Power Agency (PMPA) (responding for nine (9) municipal dept/divisions)
- South Carolina Association of Municipal Power Systems (SCAMPS) (responding for nineteen (19) Commission/Board of Public Works)

Additional interested stakeholders providing initial or responsive comments to the docket included the following:

- Carolinas Clean Energy Business Association
- Google, LLC
- Vote Solar
- Walmart, Inc.

3.4 Areas Not Evaluated

ORS's Review represents an audit-style review based on documented processes, procedures, and measures. Aspects such as proper adherence to stated processes and procedures were not included as part of the Review but represent potential areas for future evaluation.

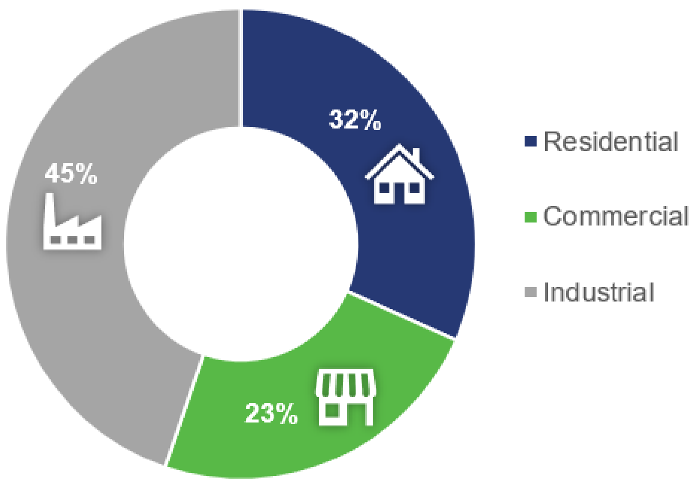
In addition, ORS recognizes that the State's power grid faces additional threats beyond winter weather events and notes that the assessment approach taken to conduct the Review may apply for other types of threats to the power system. The preliminary findings and recommendations documented in this DRAFT Report, however, specifically focus on threats and conditions similar to those faced by the Texas power grid that resulted in its multiday failure in February 2021. Evaluators did not evaluate the impacts of other threats such as hurricanes, cyber threats, extreme heat, flooding, or other threats attributed to climate change.

4 South Carolinas Power Grid

4.1 Power System Basics

South Carolinians depend on the state's power grid as an indispensable piece of their local communities. They rely on the electric power grid for cooling their homes and businesses in the humid summer months and for space heating in the winter. As depicted in Figure 1, almost one-half of the end-use energy consumed in the State (excluding energy consumed for transportation) goes to fueling South Carolina's robust manufacturing sector[10] — a sector for which the reliability and quality of the energy provided can be the most critical.

Figure 1. South Carolina Energy Consumption by End-Users, 2019 (excluding transportation)



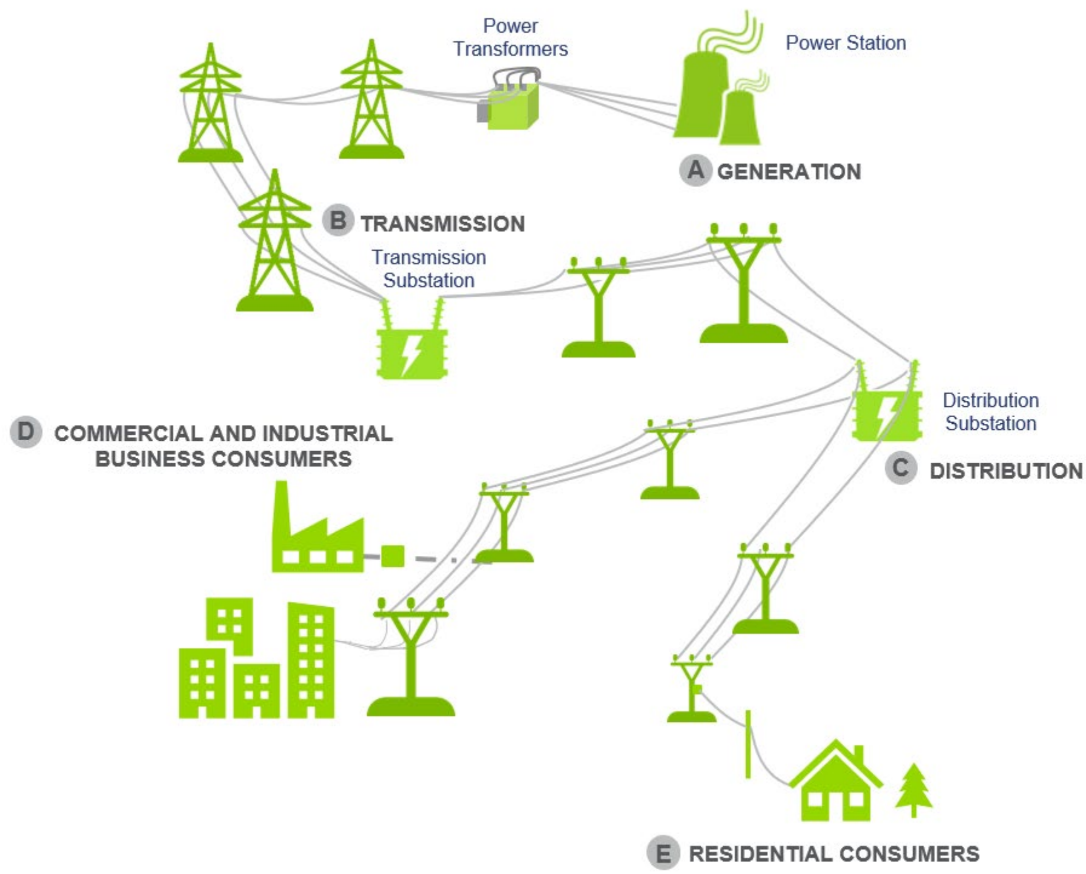
Source: Energy Information Administration, State Energy Data System

Electric Power System

South Carolina's electric power system is comprised of power generation stations, a high voltage transmission system, and a distribution system. Figure 2 offers a simplistic view of the general electric power system configuration.

[10] Energy Information Administration, State Energy Data System.

Figure 2. Overview of the Electric Power System



Electric power is generated at **A)** a power station and transported in bulk at high voltages to the communities that will consume the power via **B)** the transmission system. Once the bulk power reaches the appropriate substations, **C)** the distribution system transports power at lower voltages to end-users: **D)** businesses and **E)** homes.

Source: Guidehouse

Electric Utility Providers

According to the South Carolina State Energy Office, five (5) electric power generating utilities operate within the State (DEC, DEP, DESC, Lockhart, and Santee Cooper). In 2019, as shown in **Table 1**, these utilities produced over seventy-seven million megawatt-hours (MWh) at their fleets of generation stations. **Table 2** provides additional high-level descriptions of each of these electric utilities.

Table 1. Power Generation Utilities in South Carolina in 2019[4,11,12,13]

Electric Power Generating Utilities	Total Power Generation (MWh)	Transmission System (line-miles)	Distribution System (line-miles)
DEC	27,090,790	5,031	25,546
DEP	8,573,663	930	9,034
DESC	23,719,708	3,800	26,700
Lockhart	94,000	183	N/A
Santee Cooper	18,109,830	5,029	2,841
Total MWh Generated in 2019	**77,587,991**	**9,944**	**61,280**

Table 2. General Information about South Carolina Power Generating Utilities[4]

	South Carolina Electric Power Generating Utilities
Duke Energy *(Includes DEC and DEP)*	• Investor-owned utility headquartered in Charlotte, North Carolina that supplies electricity in parts of North Carolina, South Carolina, Florida, Ohio, Kentucky, and Indiana • Serves 30 counties in South Carolina and provide electric service to more than 733,000 retail customers • Owns and operates nearly 34,400 megawatts (MW) of generation capacity across the Carolinas, with 9,779 MW of capacity based in South Carolina
DESC	• Investor-owned utility headquartered in Richmond, Virginia that supplies electricity in parts of Virginia, North Carolina, and South Carolina • Serves roughly 698,000 electric customers across 24 counties in the central, southern, and southwestern portions of South Carolina, including Columbia, Charleston, and Aiken

[11] Lockhart Discovery Response, Re: Grid Resiliency Study Docket No. 2021-66-A, July 6, 2021

[12] Lockhart Power Company, Integrated Resource Plan, 2020. https://lockhartpower.com/wp-content/uploads/2020/08/2020-Integrated-Resource-Plan.pdf

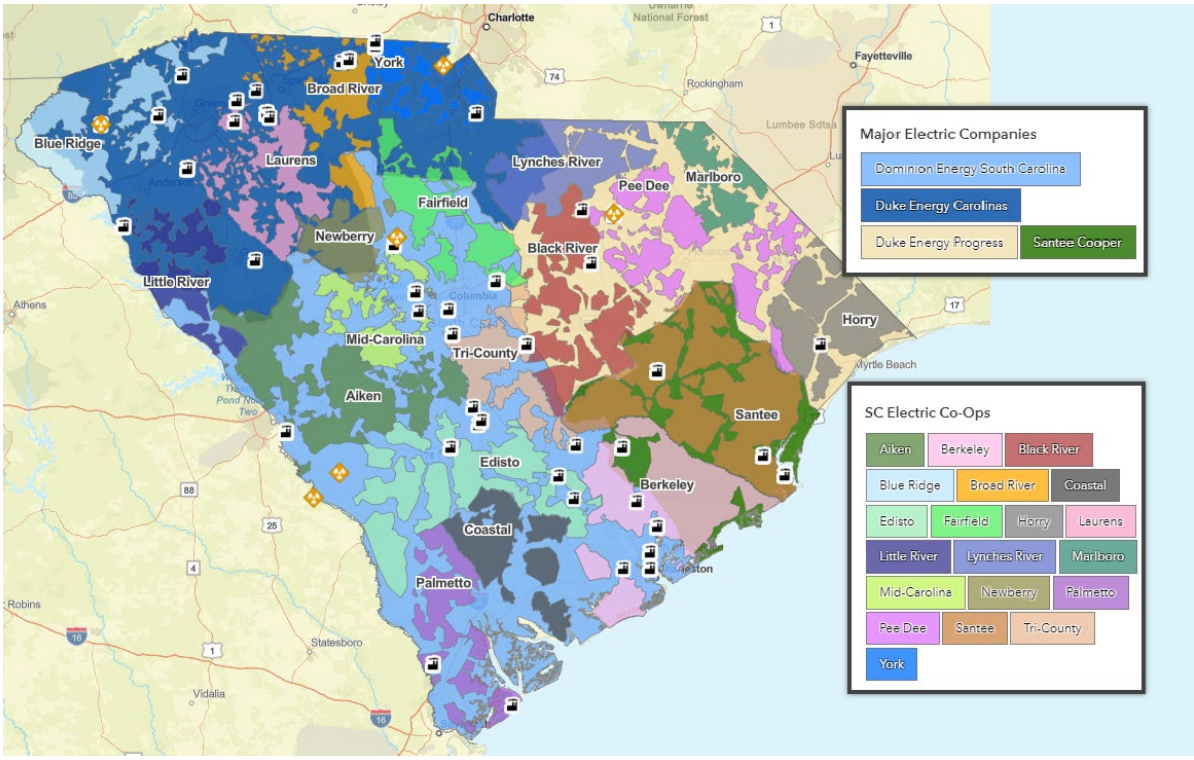
[13] Dominion Energy, Inc. Form 10k, 2020. https://s2.q4cdn.com/510812146/files/doc_financials/2020/ar/2020-Annual-Report-on-Form-10-K.pdf

	South Carolina Electric Power Generating Utilities
Lockhart	• Investor-owned electric utility located in the Upstate of South Carolina • Serves portions of five South Carolina counties: Spartanburg, Union, Cherokee, Chester, and York. • Provides power generation, transmission, distribution, and lighting services and delivers electricity to 6,160 customers: approximately 4,900 residential, 1,250 commercial, and eight (8) industrials • Peak load is typically between 70 to 80 MW with one hundred percent (100%) of the power it generates coming from renewable resources
Santee Cooper	• State-owned electric and water utility governed by a twelve-member board of directors • Public power provider and primary source of electricity, either directly or through electric cooperatives, for approximately two million people in all forty-six (46) counties of South Carolina • Serves more than 174,000 residential and commercial customers directly in Berkeley, Georgetown, and Horry counties • Supplies electricity to twenty (20) electric distribution cooperatives, the cities of Bamberg and Georgetown and twenty-seven (27) large industrial customers • Operates an integrated transmission system that includes lines owned and leased by Santee Cooper as well as those owned by Central Electric Power Cooperatives, Inc.

In addition to the five (5) electric power generating utilities, twenty-two (22) non-profit electric cooperatives and twenty-one (21) municipalities also operate electric systems within the State – primarily at the distribution system level. Twenty (20) of the independent distribution cooperatives serve approximately 720,000 members and operate more than 72,000 miles of power lines touching all 46 South Carolina counties.[4] These distribution cooperatives are supported by two statewide organizations: (1) Central Electric Power Cooperative, Inc., which provides planning, wholesale power aggregation services, and wholesale transmission delivery services, and (2) the Electric Cooperatives of South Carolina (ECSC), a statewide trade association that provides political representation, economic development support and a variety of ancillary programs to its member.[4]

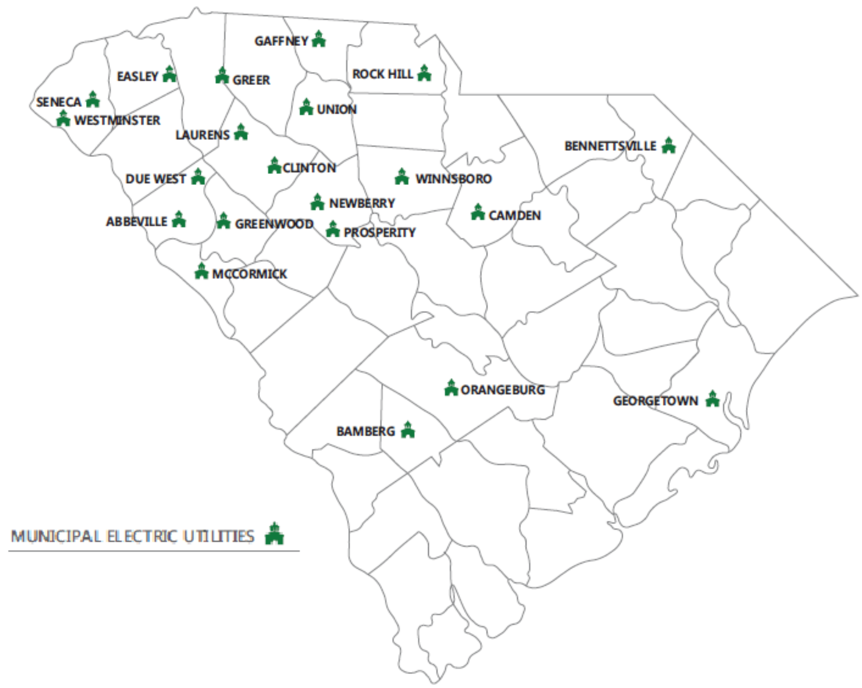
The State's twenty-one (21) municipal electric systems — electric distribution systems typically owned and operated by a city, town, county, township — provide electric service to residential, commercial, and industrial customers in their municipalities and to a limited number of customers outside of the incorporated boundaries. These local distribution systems serve approximately 170,000 customers (roughly seven percent (7%) of South Carolina's electric customers).[4] All twenty-one (21) municipal electric systems are members of the South Carolina Association of Municipal Power Systems (SCAMPS), a nonprofit organization that supports emergency mutual aid assistance coordination, training and education programs, and overall advocacy for municipal electric providers.

Figure 3 – Map of South Carolina Electric IOUs and Electric Cooperatives



Source: South Carolina Energy Office

Figure 4. Map of South Carolina Municipal Electric Utilities



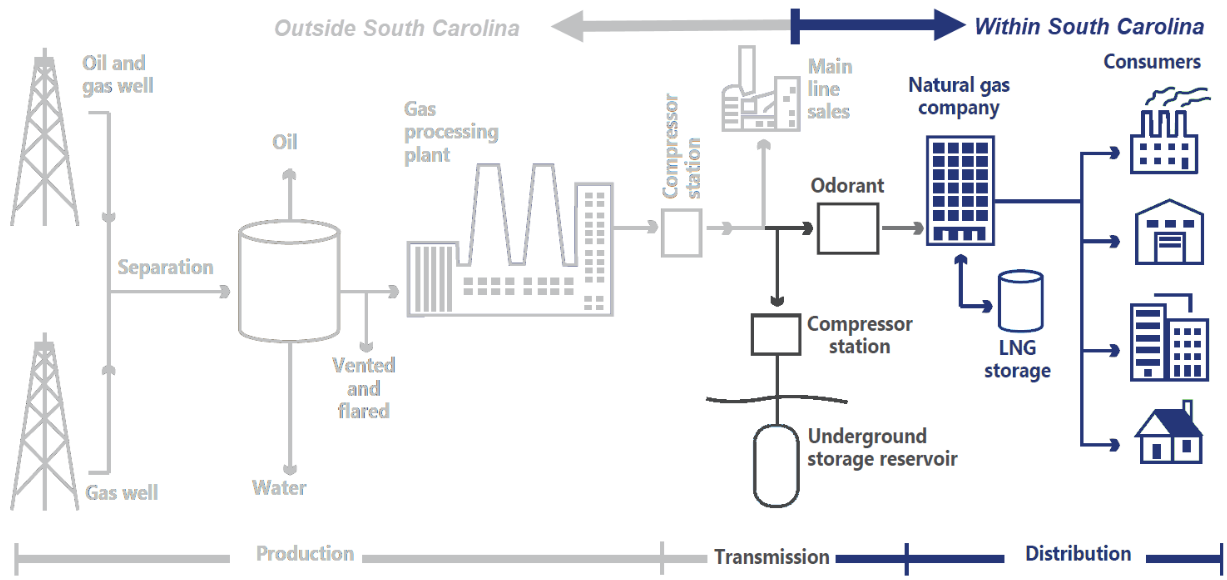
Source: SC Energy Plan

Natural Gas System

South Carolina's natural gas power system is comprised of a network of gas transmission and distribution pipelines. **Figure 5**. Natural Gas Production and Delivery offers a simplistic view of the general natural gas production and delivery system configuration.

[Additional information about the natural gas transmission network will be provided in the Final Report]

Figure 5. Natural Gas Production and Delivery



Source: SC Energy Plan, Guidehouse

Natural Gas Utility Providers

According to the South Carolina State Energy Office, two (2) natural gas investor-owned utilities operate within the State (DESC and PNG). **Table 3** provides high-level descriptions of these natural gas utilities.

Table 3. General Information about South Carolina Natural Gas Utilities[4]

South Carolina Investor-Owned and State-Owned Natural Gas Utilities	
DESC	• Investor-owned utility headquartered in Richmond, Virginia that supplies natural gas to parts of Utah, West Virginia, Ohio, Pennsylvania, North Carolina, South Carolina, and Georgia • Delivers gas to approximately 352,000 residential, commercial, and industrial customers in 35 of the 46 counties in the Midlands, Pee Dee, and coastal communities of South Carolina, including Columbia, Charleston, Aiken, Myrtle Beach, and Florence • Operates and maintains 447 miles of high-pressure transmission pipelines and 9,064 miles of distribution mains that serve South Carolina communities

South Carolina Investor-Owned and State-Owned Natural Gas Utilities	
PNG	• Investor-owned natural gas utility headquartered in Charlotte, North Carolina that supplies natural gas to parts of North Carolina, South Carolina, and Tennessee, and is a wholly owned subsidiary of Duke Energy • Serves approximately 150,000 customers and delivered approximately 20 billion cubic feet (BCF) of natural gas to its South Carolina customers in 2019 • Operates and maintains 3,789 miles of transmission and distribution mains at operating pressures between 15 and 800 psi in South Carolina • Owns and operates three publicly accessible compressed natural gas (CNG) fueling stations in South Carolina to fuel its own natural gas-fueled fleet vehicles

In addition to the two (2) investor-owned natural gas utility providers, there are fourteen (14) natural gas municipal systems operating in South Carolina. These municipal gas systems serve approximately 239,000 customers and operate and maintain approximately 9,000 miles of natural gas pipeline (representing sixty-one percent (61%) of the State's natural gas distribution network and thirty-two percent (32%) of the state's natural gas customers.[4]

For a complete list of South Carolina's electric and natural gas Utility Providers, see **Table 4**.

Figure 6. Map of South Carolina Municipal Natural Gas Utilities

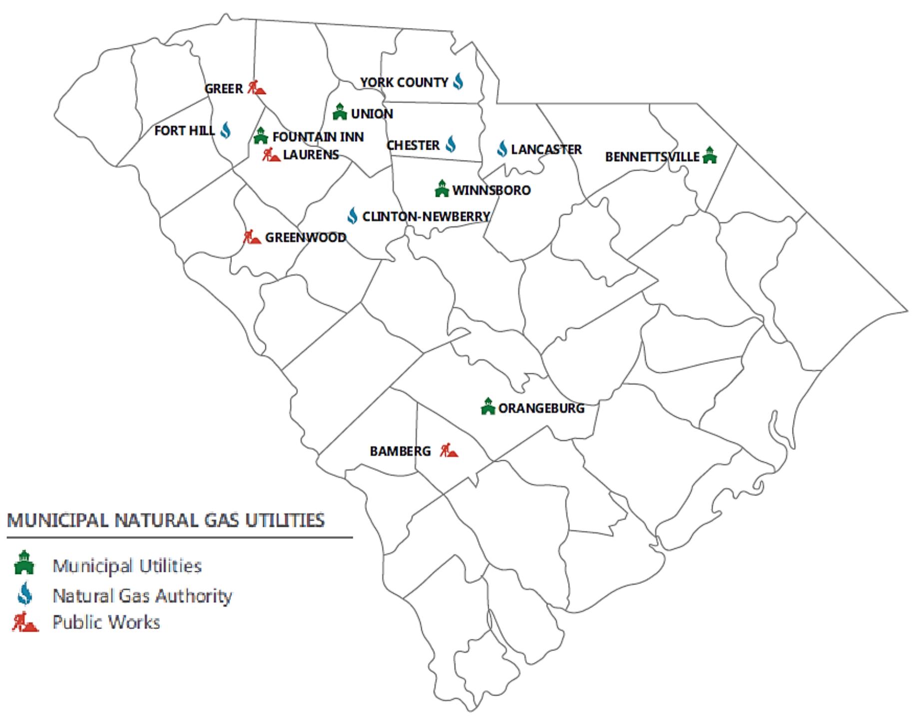


Table 4 – South Carolina Utility Providers

Electric Utility Providers	Natural Gas Utility Providers
Investor-Owned Electric Companies • DEC • DEP • DESC • Lockhart **State-Owned Utility** • Santee Cooper **Customer-Owned Electric Cooperatives** • Aiken Electric Cooperative • Berkeley Electric Cooperative • Black River Electric Cooperative • Blue Ridge Electric Cooperative • Broad River Electric Cooperative • Coastal Electric Cooperative • Edisto Electric Cooperative • Fairfield Electric Cooperative • Horry Electric Cooperative • Laurens Electric Cooperative • Little River Electric Cooperative • Lynches River Electric Cooperative • Marlboro Electric Cooperative • Mid-Carolina Electric Cooperative • Newberry Electric Cooperative • Palmetto Electric Cooperative • Pee Dee Electric Cooperative • Santee Electric Cooperative • Tri-County Electric Cooperative • York Electric Cooperative **Generation and Transmission Electric Cooperatives** • Central Electric Power Cooperative • New Horizons Electric Cooperative **Municipal Departments/Divisions** • City of Abbeville • City of Bennettsville* • City of Camden • City of Clinton • City of Georgetown • City of Newberry • City of Orangeburg* • City of Rock Hill • City of Seneca • City of Union* • City of Westminster • Town of Prosperity • Town of Due West • Town of Winnsboro* **Commissions/Board of Public Works** • Bamberg Board of Public Works* • Easley Combined Utility System • Gaffney Board of Public Works • Greenwood Commission of Public Works* • Greer Commission of Public Works* • Laurens Commission of Public Works* • McCormick Commission of Public Works	**Investor-Owned Natural Gas Companies** • DESC • PNG **Municipal Departments/Divisions** • City of Bennettsville* • City of Fountain Inn • City of Orangeburg* • City of Union* • Town of Winnsboro* **Commissions of Public Works** • Bamberg Board of Public Works* • Greenwood Commission of Public Works* • Greer Commission of Public Works* • Laurens Commission of Public Works* • Natural Gas Authorities • Chester County Natural Gas Authority • Clinton-Newberry Natural Gas Authority • Fort Hill Natural Gas Authority • Lancaster Natural Gas Authority • York County Natural Gas Authority ** Provides both electric and natural gas utility services*

4.2 Unique Characteristics of South Carolina's Power System

Across the continental U.S., local electric power grids are interconnected to form three (3) large, interconnected, but independently operated, electric power networks. These networks, or interconnections, enhance grid reliability.[14]

1) The Eastern Interconnection,
2) The Western Interconnection, and
3) Electric Reliability Council of Texas (ERCOT).

Entities (often grid operators) called "balancing authorities," or "BAs" take on the responsibility for a specific portion of the power system to ensure real-time power supply and power demand remain balanced – a required condition to avoid local or wide-area blackouts.

South Carolina's power system is part of the Eastern Interconnection.

Power System Coordination and Oversight

One of the most critical parts of South Carolina's power system is its interconnected network of high voltage transmission systems – referred to as the bulk electric system (BES) or bulk power system (BPS). Because of the interconnected nature of South Carolina's BPS with the larger Eastern Interconnection, the BPS falls under the authority the North American Electric Reliability Corporation (NERC).

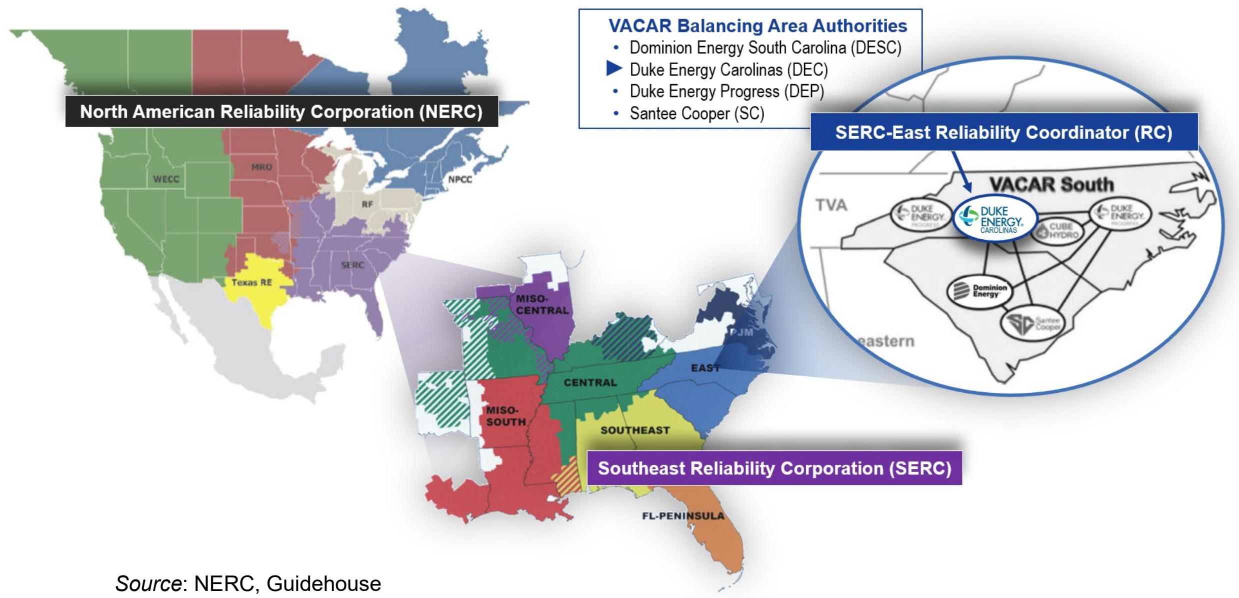
Under the authority of NERC, the electric power grid in the U.S. and Canada is comprised of six (6) regional reliability organizations of similar size and complexity. South Carolina is located within the Southeast Reliability Corporation (SERC) region. Within SERC, there are seven (7) subregions that extend from Illinois to Florida.[15] South Carolina is part of the *SERC-East* subregion, which also includes North Carolina as **Figure 7** illustrates.

---

[14] U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=27152

[15] U.S. Energy Information Administration. Electricity Market Module Regions https://www.eia.gov/outlooks/aeo/pdf/nerc_map.pdf

Figure 7 – SERC-East Balancing Area Authorities and Reliability Coordinator



Source: NERC, Guidehouse

There are major transmission ties to three (3) of SERC's subregions with import/export limits established for each subregion. For SERC-East, the import limit is approximately 3,000 megawatts (MW).[16] Notably, the capability of these interties to transfer power may be reduced during cold weather events as power system loads cause these lines to approach their operating limits.

South Carolina Balancing Area Authorities

South Carolina has four (4) BAAs within SERC-East that manage the day-to-day operation of each balancing area that is subject to NERC reliability standards and compliance.

- DEC
- DEP
- DESC
- Santee Cooper

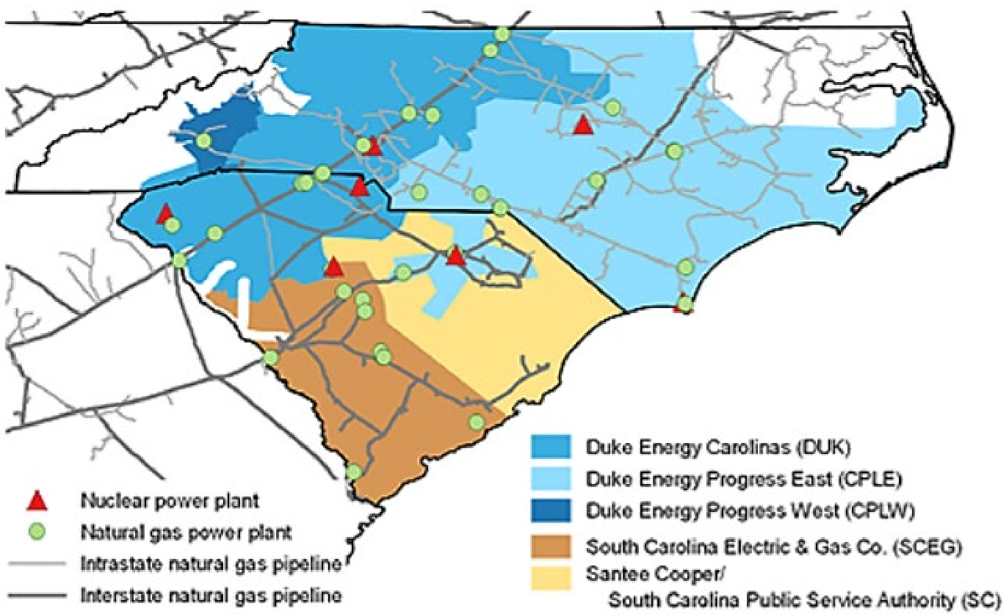
Each BAA has operational responsibility for managing the day-to-day operation of their respective balancing area. To ensure overall BPS balancing across an entire SERC subregion (e.g., throughout North Carolina and South Carolina), SERC has assigned a reliability coordinator to each SERC subregion. The SERC-East reliability coordinator responsible for monitoring the North

[16] SERC 2020 Probabilistic Assessment, Public (Redacted), Nov. 2020, Fig. 3, p.16

Carolina/South Carolina region is referred to as the Virginia-Carolinas subregion (VACAR) South; the VACAR South reliability coordinator agent registered with NERC is Duke Energy Carolinas.[17]

Because of the interconnection and coordination agreement, bulk system reliability for South Carolina must be viewed from a multi-state perspective.

Figure 8. Carolinas Balancing Authorities



Source: Energy Information Administration

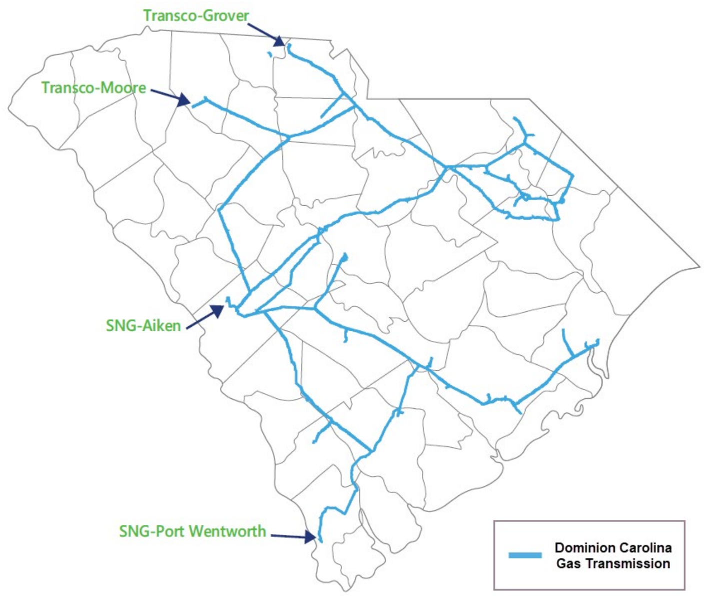
Natural Gas Supply

Another key characteristic of South Carolina's power system is that the State has no recoverable natural gas reserves or processing plants of its own. South Carolina imports its natural gas via three (3) interstate pipelines: DCGT, SNG, and Transco.[4]

Interstate natural-gas pipelines are regulated by the FERC and PHMSA under the U.S. Department of Transportation (USDOT).

[17] VACAR South Reliability Plan, August 2020, p. 16

Figure 9. Map of DCGT Gas Transmission Pipelines in South Carolina



In addition to the three (3) interstate pipelines that import natural gas, South Carolina's intrastate natural gas infrastructure consists of four (4) intrastate pipeline networks, two (2) investor owned utilities, five (5) natural gas authorities (NGAs), four (4) commissions of public works (CPWs), and five (5) municipalities.[4] Apart from pipeline safety issues, ORS does not have the responsibility for oversight of municipal systems or NGA.[4]

4.3 Comparison to the Texas Power System

Several attributes of South Carolina's power system make it materially distinct from the Texas power system – particularly as it relates to winter weather risks and performance. In the wake of the widespread Texas power system outage in February 2021, the Offices of Electric Reliability and Enforcement and NERC staff presented preliminary findings from the event and concluded that there was not a single cause that led to the outages, but rather a number of contributing factors.[18] These factors included, but are not limited to:

1. Colder than expected weather conditions leading to generation shortfalls;
2. Natural gas fuel supply issues;
3. Heavy reliance on natural gas for electricity generation (interdependency); and
4. Generation freezing issues.

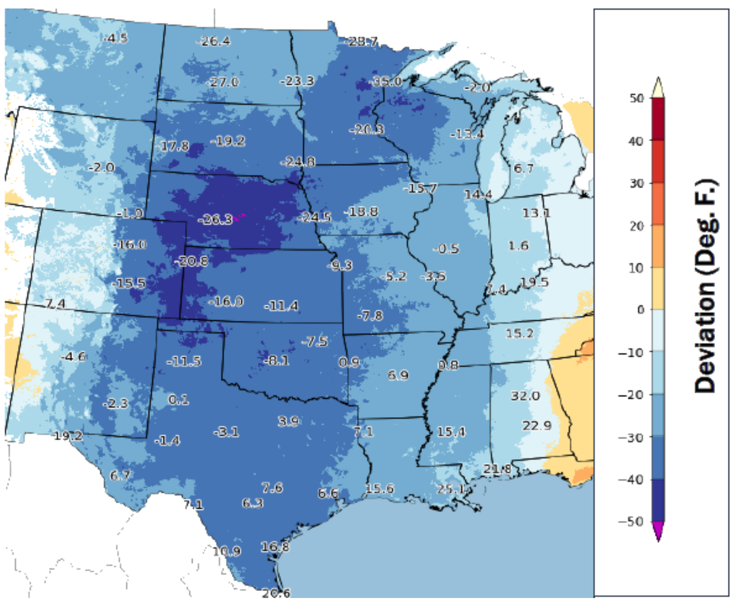
Moreover, the virtual absence of transmission ties to adjacent regional systems for most of Texas also contributed to Texas's inability to quickly import additional power in order to offset the rapidly changing power demand on the system. ERCOT, the regional interconnection of the Texas power system, operates as a single NERC reliability region.

[18] NERC, February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations. September 23, 2021. https://www.ferc.gov/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations

Colder than Expected Forecasts Leading to Generation Shortfalls

The February 2021 winter storm produced extended cold temperatures across Texas – temperatures that in some locations deviated from the average daily minimum temperature by as much as forty degrees Fahrenheit (40ºF) (**Figure 10**). Temperatures dropped to near zero in some areas while Dallas experienced single digit temperatures. This condition resulted in much higher than projected demand on the Texas power system for an extended duration as power system customers attempted to warm their homes and businesses.

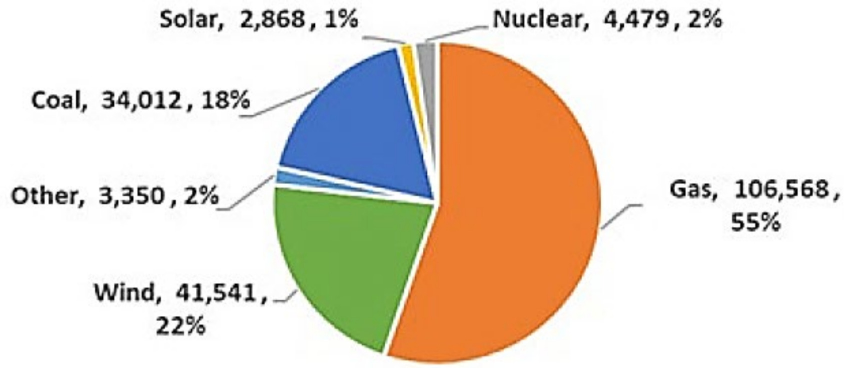
Figure 10. Minimum Temperature and Departure from Average Daily Minimum



Source: NOAA

In addition to the unexpected increase in customer demand, as the cold temperatures persisted for two consecutive days, ERCOT averaged 34,000 MW of generation outages. Of the generating units experiencing outages, derates or failures to start, over half were natural gas generators (**Figure 11**). To ensure system stability, the BAs working to balance the State's energy demand with the dropping supply, ordered grid operators to shed over 20,000 MW of load.[18]

Figure 11. Fuel Type of Generating Units that Experienced Unplanned Outages and Derates



Source: NERC

Reliance on Natural Gas for Electricity Generation (Interdependency)

Texas is a large natural gas producer and consequently has a high reliance on natural gas, both for direct end-use and to fuel the State's electric generation facilities. As Figure 12 illustrates, in 2019 natural gas made up nearly two-thirds of all energy consumed by the State. By contrast, in South Carolina, just over one-fourth of energy consumed was natural gas over the same period.[10] Further, more than half of electricity produced in Texas is fueled by natural gas. This level of reliance on natural gas for electricity production creates a strong interdependency between natural gas and electricity in Texas. In South Carolina, less than one-quarter of electricity production is fueled by natural gas (Figure 13).

During the February cold snap, when temperatures in Texas averaged nearly 30 degrees Fahrenheit lower than normal, natural gas production in Texas fell almost forty-five percent (45%). According the U.S. Energy Information Administration, this decline in natural gas production was mostly a result of water and other liquids in the raw natural gas stream freezing at wellheads or in natural gas production lines. Unlike the relatively winterized natural gas production infrastructure in northern areas of the country, natural gas production infrastructure in Texas is more susceptible to the effects of extremely cold weather.[19]

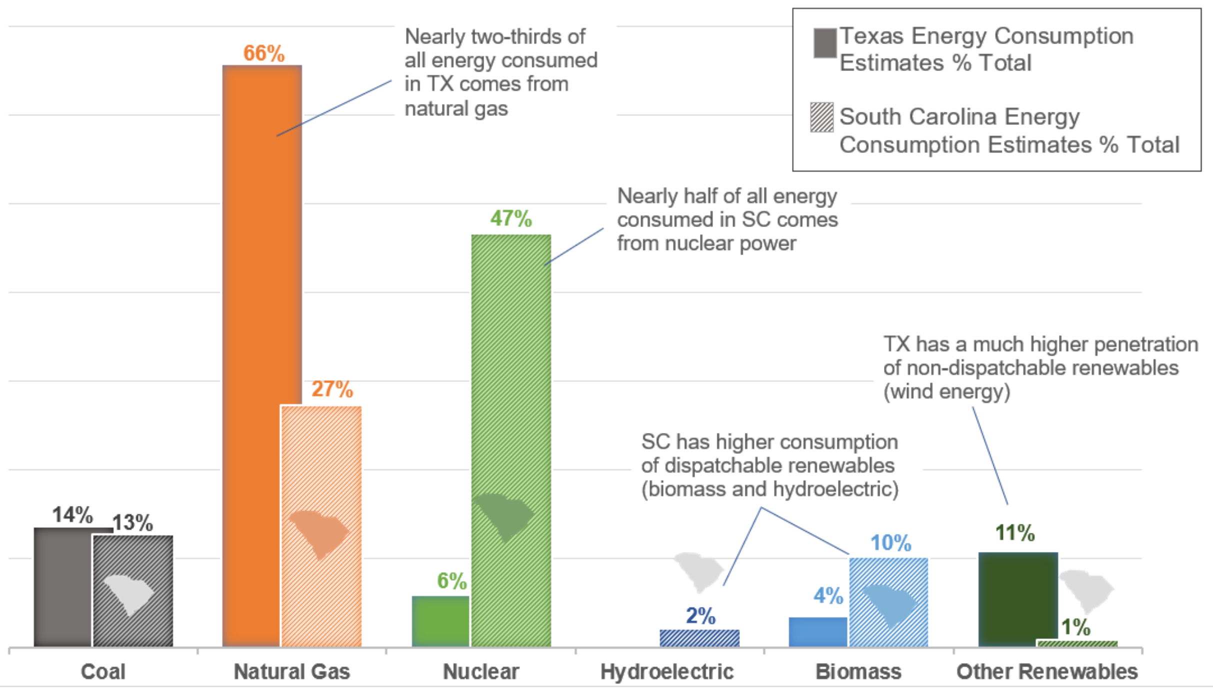
In South Carolina, the greatest amount of power consumed in the State comes from nuclear generation. Moreover, the natural gas supply that South Carolina imports is sourced from a variety of locations including the Gulf Coast, Mid-Continent, and Appalachia.[20]

---

[19] U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=46896

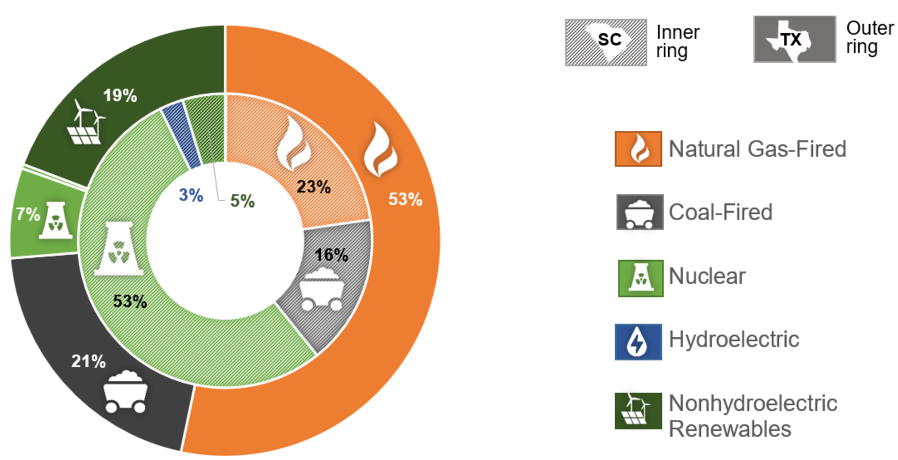
[20] Williams. https://www.williams.com/pipeline/transco/

Figure 12. Energy Consumption by Fuel Type for South Carolina and Texas, 2019



Source: U.S. Energy Information Administration, Guidehouse

Figure 13. Percent of Net Electricity Generation for Texas and South Carolina by Fuel Type



Source: U.S. Energy Information Administration, Guidehouse

Loss of Renewable Generation

Figure 12 also highlights South Carolina's lower reliance on variable energy resources. Texas leads the nation in wind-powered generation and produced more than twice as much electricity from wind as from its two (2) nuclear power plants combined in 2020.[10]

By contrast, the renewable power consumed in South Carolina comes primarily from dispatchable resources, such as hydroelectric power and biomass. Dispatchable resources can offer more flexibility for system operators – particularly during times of sharp changes in demand and supply.

Interconnectedness of the Regional Transmission System

Perhaps one of the most impactful differences between the South Carolina and Texas power systems is the level of interconnectedness each has with its neighboring power systems. The Easter Interconnection system, of which South Carolina is a part, is far more interconnected than the ERCOT.

[Final Report to include broader discussion and a graphical view of the strong VACAR-South interties to adjacent systems within and outside of SERC]

5 Threats and Vulnerabilities from Winter Weather Events

The transmission elements of the electric system, the portion of the electric power system that is operated at voltages of 100 kilovolts (kV) or higher, and Real Power and Reactive Power resources connected at 100 kV or higher, is an especially critical part of the electric system.[21] This part of the power grid – referred to interchangeably as the BPS or BES – connects power generation stations to the power grid, and interconnects multiple electric power systems together in a way that allows power to flow from one region to another.

NERC, a national regulating body of the BPS, defines reliability of the system using two functional attributes: *adequacy* and *operating reliability*.

> *Adequacy* is the electric power system's ability to supply the total (aggregate) electric power and energy requirements of all electric power customers at any given time – including during scheduled and expected unscheduled outages of system components.
>
> *Operating reliability* is the electric power system's ability to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system component.

---

[21] National Electric Reliability Corporation, Bulk Electric System Definition Reference Document, Version 3, August 2018.
https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf.

[Final to include statement about any SERC-East adequacy and operating reliability assessment findings]

South Carolina's power grid consists of critical transmission and distribution (T&D) assets that are geographically dispersed but that must be secure and provide interconnectedness and stable balancing to power the state's water, transportation, communications, and economic infrastructures. Winter weather events or conditions might materialize in South Carolina that could significantly damage or disrupt utility service. To what degree utility systems and infrastructure could be impacted from weakness within these systems, processes, or infrastructure must be understood to assess for proper mitigation of such risks.

5.1 Risks and Threats to South Carolina's Utility Services

While the top weather threats to the region are related to heat, humidity, and flooding, one of the greater risks could come from low probability events such as extreme cold, snow, or ice if the State's utility sector is not adequately prepared for such rare but highly consequential events. In its 2020 Reliability Assessment report for its subregions including SERC-East, SERC identified several general risk factors with higher likelihood and high impacts:[22]

- Changing resource mix (e.g., increased reliance on renewables or natural gas);
- Variable energy resources integration;
- Cybersecurity threats resulting from external and internal vulnerabilities;
- Resource uncertainty;
- Fuel diversity and fuel availability; and
- Weather-related (including winter events).

For weather-related high priority risks and fuel supply-related risks, SERC identified mitigation actions that members should undertake. **Table 5** provides a list of these actions. SERC recommends risks be proactively addressed through operating procedures and standards, including emergency operating procedures (EOPs), transmission operating procedures, or transmission plans (TPLs).

[22] SERC Reliability Review Committee, 2020 Annual Assessment. https://online.flippingbook.com/view/916658/

Table 5 – High Priority Risk Mitigation Actions Identified by SERC[22]

Addressing High Priority Risks to SERC Members
For Weather-Related Risks • Required reporting of extreme events • Extreme weather resiliency measures for network modeling, state estimation, and real-time contingency assessment (RTCA) • Identification of backup measures if RTCA primary tools fail (e.g., state estimator fails to solve) • Use of alternate tools for manual operation of system or loss of situational awareness • Response plan for loss of communication data or voice • Emergency planning for extreme weather conditions
For Fuel Supply-Related Risks • Resource adequacy • Situational awareness measures for sudden changes in dispatch and operating conditions • Identification of forced operating conditions • Fast-acting capabilities of existing units • Response plan for a significant event that would affect specific fuel types • Increased reliance on natural gas

5.2 Potential Vulnerabilities in South Carolina's Utility Infrastructure

The variety of asset types and geographic dispersion of the State's utility infrastructure introduce general vulnerabilities consistent with those faced by the critical infrastructure of any sector, including sabotage, unforeseeable natural hazards, and accidental third-party damage. For such vulnerabilities, the most critical infrastructure is equipped with a constantly evolving set of design standards and protective measures to prevent as much potential impact as practical and with emergency response plans to quickly mitigate any harm done. For South Carolina's critical utility infrastructure, this is also the case.

Aside from the more general vulnerabilities of the South Carolina power system (e.g., asset corrosion, equipment malfunction, human error), the State's electric and natural gas utility providers identified vulnerabilities specific to winter weather events. **Table 6** provides a subset of those identified by Utility Provider in their responses to ORS information requests.

Table 6 – Vulnerabilities Identified by South Carolina Electric and Natural Gas Utility Providers

Winter Weather-Related Power System Vulnerabilities in South Carolina
Environmental Conditions • **Predictability of winter weather events:** Unlike the long planning runways of hurricanes and other tropical weather, the nature of extreme cold weather events (temperature, wind, icing, duration) are far less predictable. • **Changes to pre-existing conditions:** More frequent and extreme shifts in the environment (extreme heat, excessive humidity, prolonged drought, etc.) can produce unknown changes to local vegetation and equipment conductions, leading to new and unrecognized pre-existing conditions during winter weather events. • **Ice accumulation:** The moderate climate in South Carolina contributes to the threat from ice storms (temperatures may not be cold enough to produce snowfall but cold enough to cause ice accumulation on power lines or trees near power lines). • **Falling limbs:** Following ice storms, falling trees and limbs pose a danger to line crews, delaying or suspending restoration efforts, sometimes for days, until the ice melts and the threat to crews passes.
Resource and Fuel Supply • **Interruptible gas curtailment:** During periods of high demand (or supply limitations due to freeze-ups), interruptible gas supply for electric generation may be curtailed. • **Availability of replacement materials:** During widespread catastrophic issues or events, high demand replacement materials (e.g., transformers, mobile substations, conductors, or specialty items) experience a surge in demand, limiting access and availability. • **Wholesale power availability:** Regionwide events such as extreme cold significantly limit the availability of purchased power from other utilities or emergency power from VACAR during critical peak loads as neighboring utilities withdraw power available for sharing to meet their own needs. • **Electric generation reserves:** In prolonged extreme cold conditions, as peak load increases, electric generation reserves diminish, increasing the system's vulnerabilities to sudden generation loss. • **Limitations in forecasting:** The unpredictability of extreme cold can drive inaccuracies in load forecasts and resource planning that ultimately leads to under-resourced utilities during emergency conditions.

Winter Weather-Related Power System Vulnerabilities in South Carolina

Labor Force

- **Access to labor force:** During severe outage events, particularly those driven by widespread natural disasters or multiple weather events over a short duration, availability of construction contractors and mutual aid crews becomes limited.
- **Access by labor force:** Due to hazardous road conditions and other threats to winter weather-related mobility issues, employees, contractors, or human resources necessary to resolve issues may be unavailable.

Winter Weather-Related Power System Vulnerabilities in South Carolina

Infrastructure and System Design

- **System strain from cold:** Systems and resources that can withstand short periods of cold weather are not necessarily equipped to sustain operation or function over long periods of cold weather (e.g., traditional peaking capabilities not designed for continuous operations, instrumentation, process systems, and fuel supplies, including natural gas and coal piles).
- **Distribution system strain from load:** Extreme peak loads that occur when weather is much colder or more prolonged than average peak condition can lead to damaged equipment (e.g., overloaded distribution lines and distribution transformers), causing cold weather outages.
- **Transmission system strain from load:** Extreme peak loads that result in the transmission system operating closer than normal to the facility rating limits operational flexibility to import power from off-system capacity for reserve sharing and the ability to pick up significant volumes of load when needed.
- **System strain with intermittency:** When the system is strained due to cold temperature exposure or extreme loads, intermittency from solar generation may exacerbate system stability challenges.
- **Supply balancing:** Abrupt changes in demand caused by a downed transmission line or large transformer failure that led to a lower-than-expected load can pose a significant challenge to the balancing authority's ability to balance generation resources. When aggregate loads reach values below the minimum capabilities of the system's generating resources, generating units would need to be taken offline; recovering from such an outage event, including the effects of cold load pickup, becomes more challenging.
- **Power line (feeder) exposure:** Long radial feeders that lack the tie points that allow backfeeding of power for loss of primary source or any single component outage are especially susceptible to the wind and falling trees that accompany winter weather events. Overhead distribution facilities, prevalent in rural areas, are not designed to carry the excess weight of snow and ice.
- **Pipe exposure:** Extended periods of below-freezing temperatures can freeze unprotected exposed service water piping, condensate piping, and instrumentation lines that do not maintain flow. Frozen piping can disrupt control and piping damaged from a freeze may leak as it thaws, creating more operational challenges and even force whole generating units offline.
- **Overwhelmed steam supply line:** The combination of cold temperatures and high winds can overwhelm the natural gas station steam supply line, leading to overheated circuits and impacts to generation capacity.

To address these vulnerabilities and others, many sectors, including the power sector, rely on historical data and trends to identify and attempt to protect against vulnerabilities. Unfortunately, in today's environment of rapid innovation, technology advancement, and evolving geopolitical outlooks, forecasting based on historical patterns and events may not position the industry well to plan for future events.

6 Evaluation Approach

Guidehouse's electric, natural gas, and utility operations professionals (Evaluators) evaluated the utility information and assessments on behalf of ORS. The Evaluators applied a Utility Adverse Weather Assessment Framework (Assessment Framework) that was adapted for winter weather events.

6.1 Evaluation Categories

To enable reasonable comparisons of capabilities and to compensate for varying service area sizes and the significant resource gaps between, for example, large investor-owned utilities and smaller local providers, Evaluators clustered the utility providers into four (4) assessment groups based on the general sizes and services provided.

- Large investor-owned or state-owned electric utilities (LEUs)
- Large investor-owned natural gas utilities (LGUs)
- Smaller electric municipal departments, boards, or commissions or customer-owned electric cooperatives (SEUs)
- Smaller natural gas municipal departments, boards, or commissions (SGUs)

Although, in cases such as that for municipal utilities and electric cooperatives, the utility operating models are uniquely distinct from one another, because of the relevance of findings and applicability of the recommendations, Evaluators included both utility types in the same assessment group.

The preliminary findings and resulting recommendations from this review are consolidated by utility provider type (natural gas and electric utilities) and utility size (large utilities and smaller utilities), as described above.

Table 7 identifies which utilities were assessed individually, which utilities were evaluated as part of a group of utilities, and the consolidated categories in which each entity was placed.

Table 7 – Evaluations Conducted by Utility Category

LEUS *(Four Evaluations)*	**SEUS** *(Six Evaluations)*	
1) DEC 2) DEP 3) DESC 4) Santee Cooper	1) Central Electric Power Coop. 2) **Electric Cooperatives of South Carolina** ○ Aiken Electric Coop. ○ Berkeley Electric Coop. ○ Black River Electric Coop. ○ Blue Ridge Electric Coop. ○ Broad River Electric Coop. ○ Coastal Electric Coop. ○ Edisto Electric Coop. ○ Fairfield Electric Coop. ○ Horry Electric Coop. ○ Laurens Electric Coop. ○ Little River Electric Coop.	6) **South Carolina Assoc. of Municipal Power Systems** ○ Bamberg Board of Public Works ○ City of Abbeville* ○ City of Bennettsville ○ City of Camden ○ City of Clinton* ○ City of Georgetown ○ City of Newberry* ○ City of Orangeburg ○ City of Rock Hill* ○ City of Seneca ○ City of Union ○ City of Westminster *
LGUS *(Two Evaluations)*		
1) DESC 2) PNG		

SGUS *(Seven Evaluations)*

1) City of Union Municipal Dept
2) Clinton-Newberry Natural Gas Authority
3) Fort Hill Natural Gas Authority
4) Greenwood Commission of Public Works
5) Greer Commission of Public Works
6) Laurens Commission of Public Works
7) **Patriots Energy Group**
   - *Chester County Natural Gas Authority*
   - *Lancaster Natural Gas Authority*
   - *York County Natural Gas Authority*

   - Lynches River Electric Coop.
   - Mid-Carolina Electric Coop.
   - Newberry Electric Coop.
   - Palmetto Electric Coop.
   - Santee Electric Coop.
   - Tri-County Electric Coop.
   - York Electric Coop. Inc
3) Lockhart
4) Marlboro and Pee Dee Corp.

5) **Piedmont Municipal Power Agency**
   - City of Abbeville
   - City of Clinton
   - City of Newberry
   - City of Rock Hill
   - City of Union
   - City of Westminster
   - Easley Combined Utility System
   - Gaffney Board of Public Works
   - Greer Commission of Public Works
   - Laurens Commission of Public Works

   - Easley Combined Utility System*
   - Gaffney Board of Public Works*
   - Greenwood Commission of Public Works
   - Greer Commission of Public Works
   - Laurens Commission of Public Works *
   - McCormick Commission of Public Works
   - Town of Prosperity
   - Town of Due West
   - Town of Winnsboro

** Supported by responses from both SCAMPS and PMPA*

6.2 Assessment Methodology and Framework

This Assessment Framework leverages a Capability Maturity Model Integration (CMMI) process and behavioral model. The CMMI process, created by the Carnegie Mellon University Software Engineering Institute,[23] has often been applied to help organizations understand and streamline process improvement, encourage productivity, and improve effectiveness. One common example of a CMMI model used in the power industry is the Smart Grid Maturity Model, a framework used by electric utilities to assess the maturity of a smart grid deployment.

The CMMI-based Assessment Framework applied in the ORS Review allowed Evaluators to assess the maturity of a utility's ability to withstand adverse winter weather and assign that area into one of five levels of maturity.

The maturity level is a result of the weighted score for each indicator:

- ***Nascent*** (scores 1 or less) signifies lacking or undeveloped foundational components
- ***Lagging*** (scores greater than 1 to 2) signifies some foundational components in place
- ***Foundational*** (scores greater than 2 to 3) signifies foundational components in place and current standards followed
- ***Leading*** (scores greater that 3 to 4) signifies foundational components in place and forward-looking plans or practices

[23] Carnegie Mellon University, Software Engineering Institute. https://resources.sei.cmu.edu/library/asset-view.cfm?assetid=11955

- ***Advanced*** (scores greater than 4) signifies advanced components in place and positioned for emerging needs

Evaluators consider the higher end of Level 4 to Level 5 as ***high maturity***, in which Utility Providers are continuously evolving, adapting, and growing to meet the needs of stakeholders and customers. This is considered leading performance. Across most assessment areas, Evaluators consider utility providers that achieve the higher end of Level 2, Level 3, and the lower end of Level 4 as ***adequate maturity***. These Utility Providers are considered to be on par with their peer Utility Providers. Level 1 to the lower end of Level 2 is considered as ***needing improvement***. These utilities are starting out in their maturity journey and need to improve on some key processes.

The Assessment leverages a continuous representation for defined adverse weather process areas and defines capability levels to characterize improvements. The process areas were defined specifically for preparation and response to adverse weather impacts and enables comparisons across organizations on a process area-by-process area basis. The Assessment Framework allowed the Evaluators to assess utility systems, measures, and practices more consistently across Utility Providers and more comprehensively across the eleven (11) indicator areas. **Table 8** describes the eleven (11) indicator areas the Evaluators considered.

Table 8 – Assessment Framework Indicator Areas

Assessment Framework Indicator Areas	
Indicator 1 – Emergency Management and Planning	Emergency management planning and preparation is critical for effective response to potential ice storms and dangerous winter weather conditions.
Indicator 2 – Risk Management	Critical infrastructure risk management plans must be developed, and preventative mitigation actions must be identified in advance of adverse weather.
Indicator 3 – Staffing and Mutual Assistance Support	Resource planning and acquisition must be sufficient for response to large-scale emergencies.
Indicator 4 – Asset Management and Inspections	Asset management practices and asset inspections must assure that critical infrastructure will properly operate during adverse weather events.
Indicator 5 – Operational Protocols	Adverse weather operational protocols must be implemented, and employees must be prepared, knowledgeable, and trained.
Indicator 6 – System Design and Hardening	The resilient electric or gas utility invests resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers.
Indicator 7 – Stakeholder Engagement	Stakeholder engagement is critical to accurately communicating and developing a utility's resilience strategies and plans, recognizing roles and responsibilities of the community, identifying opportunities for improvement, and implementing solutions that align with stakeholder values and needs.

Assessment Framework Indicator Areas	
Indicator 8 – Public Communications	Effective communication of resilience information by utilities helps to foster transparency in resilience gaps related to climate hazards, raise industry and community awareness of the activities that are either planned or currently in use to close those gaps, and disseminate effective resilience strategy guidance to close those gaps within the industry and across the nation.
Indicator 9 – Automation	Organizations that have achieved a high level of maturity within this domain have an increased capability to use automation and information available from the deployment of smart grid technologies. These organizations have the capability to manage power flows so that power losses are minimized, and the usage of lowest cost generation resources are maximized.
Indicator 10 – Situational Awareness	Situational awareness approaches and technologies enable utilities to have a more informed, comprehensive, and actionable preparation and response to severe weather events.
Indicator 11 – Regulatory Compliance	Utilities are required to adhere to federal, state, or local reliability and resilience requirements including but not limited to joint reliability plans and assessments, coordinating agreements, and wholesale purchase agreements

Evaluators then assessed each indicator area across the five evaluation categories. **Appendix A** describes how each of the following five (5) evaluation categories are considered within the eleven (11) Assessment Framework indicator areas.

- People and culture
- Governance
- Process
- System and technology
- Data and analytics

The Assessment Framework provided Evaluators a consistent methodology to assess utility provider maturity for the eleven (11) indicator areas of adverse weather resilience and to compare their performance against leading industry practices. Evaluation across the five (5) categories offered greater depth of analysis to identify strengths and improvement needs. The approach taken allowed Evaluators to initially look for trends and may support Utility Providers in tracking improvements in the future.

Moreover, Evaluators further segmented their review of the LEUs to consider the impacts of extreme winter weather events on energy generation, bulk power delivery services, and utility distribution services. For Utility Providers that provided both natural gas and electric services or for Utility Providers that offered both bulk power and distribution services, Evaluators conducted separate evaluations for those areas.

For example, for DESC, a Utility Provider that provides bulk power services, electric distribution, and natural gas services, Evaluators conducted separate reviews for each type of utility service. Conversely, those entities for which information request responses were provided as part of a collective response (i.e., a single organization provided information and assessments on behalf of multiple providers, such as the ECSC), Evaluators conducted a single evaluation of the body of information provided.

Assessment Process

[Final Report will include a description of the discovery process along with an overview of the number and types of documents provided by Utility Providers and reviewed by Evaluators.]

7 Overview of Preliminary Findings

Evaluations of Utility Provider information and assessments were conducted by categories based on utility type and utility size. Consistent with previous sections, the four evaluation categories are LEUs, LGUs, SEUs, and SGUs. A summary of preliminary evaluation findings and initial recommendations based on the material provided by the participating Utility Providers are provided in the following subsections.

7.1 Preliminary Findings

Notably, the large utilities (LEU and LGU) have the greatest risk on the winter weather resiliency of the South Carolina power grid and their ability to withstand winter weather events. This preliminary finding reflects the dominance of electric power use in heating across the State during the winter season and the growth of natural gas as a fuel source in the electric power sector. SEUs and SGUs, while vital to the communities they serve, pose a much lower risk to the statewide infrastructure should they experience localized failures within their systems. A transmission line outage for an LEU carries the potential to cause additional outages on another part the transmission system under certain high-power usage or limited power supply conditions. This risk is exponentially lower for distribution infrastructure failures at SEUs or SGUs.

Given the information provided by the participating Utility Providers, the **Evaluator's preliminary findings deemed the South Carolina power grid to be *adequately mature* in its ability to withstand potential ice storms and other winter weather events**. The State's Utility Providers, and in particular the LEUs and LGUs, offered enough qualitative evidence to illustrate their readiness and ability to respond to winter weather events, including the functionality and capabilities introduced into the infrastructure to respond to these types of events. The Evaluators initial findings are based on documented practices and plans of Utility Providers. The Final Report will incorporate an assessment of additional information provided by utility providers that will help demonstrate proper and effective implementation of those procedures and plans assessed by Evaluators.

7.2 Summary of Support for Preliminary Findings

Table 9 summarizes the overall Assessment Framework scoring and associated maturity level by indicator area for each utility category (LEU, LGU, SEU, and SGU).

Table 9 – Maturity Level Assessment Summary by Utility Provider Type and Size

	Score Summaries			
Indicator	**LEU**	**LGU**	**SEU**	**SGU**
Indicator 1 – *Emergency Management and Planning*	**3.7**	**3.2**	**2.5**	**Not rated***
Indicator 2 – *Risk Management*	**3.5**	**3.4**	**2.3**	**2.4**
Indicator 3 – *Staffing and Mutual Assistance Support*	**3.3**	**2.6**	**2.6**	**Not rated***
Indicator 4 – *Asset Management and Inspections*	**3.3**	**3.0**	**1.6**	**Not rated***
Indicator 5 – *Operational Protocols*	**3.6**	**3.0**	**2.4**	**Not rated***
Indicator 6 – *System Design and Hardening*	**3.3**	**3.1**	**1.6**	**2**
Indicator 7 – *Stakeholder Engagement*	**2.9**	**3.4**	**1.5**	**Not rated***
Indicator 8 – *Public Communications*	**3.6**	**3.4**	**1.8**	**Not rated***
Indicator 9 – *Automation*	**2.8**	**N/A**	**1.0**	**N/A**
Indicator 10 – *Situational Awareness*	**3.6**	**2.7**	**1.8**	**Not rated***
Indicator 11 – *Compliance to Regulations*	**2.4**	**3.4**	**2.1**	**2.7**

* *Not Rated* means not calculated due to insufficient response

Summary highlights of the preliminary findings are captured below. Full summaries of Evaluators' findings by utility category will be included in the Final Report.

Key Preliminary Findings

Overall, the LEU entities are adequately mature in their ability to withstand potential ice storms and other winter weather events. **Table 10** summarizes the preliminary key findings for Large Electric Utilities.

Table 10 – Preliminary Key Findings - Large Electric Utilities

Indicator	Maturity	Preliminary Key Findings
Indicator 1 – *Emergency Management and Planning*	Leading	Leading level of maturity in emergency management planning and preparation - the Incident Command System (ICS) structure has been fully integrated. Emergency management teams are trained specific to their roles. Personnel training programs are the fully tracked. Personnel competency on the business continuity plan is part of personnel training programs.
Indicator 2 – *Risk Management*	Leading	Leading level of maturity in developing infrastructure risk management – LEU entities adequately described the various processes and procedures they use to assess and evaluate winter weather threats and risks to safe and reliable electric service, as applicable. They have well-documented storm plans that identify potential risks that may impact the system.
Indicator 3 – *Staffing and Mutual Assistance Support*	Leading	Leading level of maturity in resource planning and acquisition for responding to large-scale emergencies. LEU entities have established arrangements for mutual aid. Various programs were created to formalize agreements between entities to prepare for major events, most of which addresses supply chain issues.
Indicator 4 – *Asset Management and Inspections*	Leading	Leading level of maturity in asset management practices and asset inspections to assure that critical infrastructure will properly operate during adverse weather events. LEU entities provided sufficient documentation depicting their asset management and inspection programs. Common use internal lessons learned (following outages and major events) to continuously improve on their preparation and response to extreme weather events. The use of technology and tools to enhance asset management is a prevalent practice.
Indicator 5 – *Operational Protocols*	Leading	Leading level of maturity in implementing adverse weather operational protocols. Their employees are prepared, knowledgeable, and trained. Operating procedures appear to be robust as reported by the LEU entities.
Indicator 6 – *System Design and Hardening*	Leading	Leading level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers. LEU entities demonstrated adequate processes to keep up with current standards and have invested in resiliency as necessary (based on the information in the capital plans they provided). They have provided adequate documentation that depicted the overall approach to how entities' respective planning organizations perform the annual transmission system assessments. LEU entities appropriately described their distribution planning standards and their loading criteria.
Indicator 7 – *Stakeholder Engagement*	Foundational	Foundational level of maturity in accurately communicating and developing a utility's resilience strategies and plans with their stakeholders. In general, the LEU entities have identified key stakeholders and have devised communication plans. Critical facility identification and prioritization is not widely practiced—this is an improvement opportunity.

Indicator	Maturity	Preliminary Key Findings
Indicator 8 – *Public Communications*	Leading	Leading level of maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards. The LEU entities generally raise industry and community awareness of the activities that are either planned or currently in use to close those gaps and disseminate effective resilience strategy guidance to close those gaps within the industry and across the nation. Notably, the LEU entities are consistent in incorporating technology into their communication plans
Indicator 9 – *Automation*	Foundational	Foundational level of maturity in the use of automation and information available from the deployment of smart grid technologies. LEU entities demonstrate a prevalent use of their geographic information system (GIS) to automate the dissemination of information for severe weather planning and operations. However, little information was provided on distribution automation (DA). LEU entities generally take advantage of technology to automate (where possible) key processes in assisting their damage assessment.
Indicator 10 – *Situational Awareness*	Leading	Leading level of maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events. LEU entities reported having the foundational tools and processes for situational awareness.
Indicator 11 – *Compliance to Regulations*	Foundational	Foundational level of maturity in adhering to federal, state, or local reliability and resilience requirements. LEU entities are subject to extensive regulatory oversight by the state and federal government through various regulatory agencies; the entities have demonstrated via specific references to federal and state laws the adequacy and quality of service and their internal practices. Transmission operations and planning appears to be in compliance with applicable NERC reliability standards and guidelines. Readiness plans have been established to address short- and long-term transmission upgrades to ensure no loading or voltage violations for system contingencies.

Overall, the LGU entities are adequately mature in their ability to withstand potential ice storms and other winter weather events. **Table 11** summarizes the preliminary key findings for Large Natural Gas Utilities.

Table 11 – Preliminary Key Findings - Large Natural Gas Utilities

Indicator	Maturity	Preliminary Key Findings
Indicator 1 – *Emergency Management and Planning*	Leading	Leading level of maturity in emergency management planning and preparation. The ICS structure or equivalent has been fully integrated into the LGU entities' enterprise culture. By using the ICS structure, they demonstrate the use of standardized approach to the command, control, and coordination of emergency response, providing a common hierarchy within which responders from multiple agencies can be effectively managed before, during, and after a major event.

Indicator	Maturity	Preliminary Key Findings
Indicator 2 – *Risk Management*	Leading	Leading level of maturity in developing infrastructure risk management. The LGU entities provided comprehensive DIMPs and TIMPs. However, formal programs for severe winter weather risks were not identified.
Indicator 3 – *Staffing and Mutual Assistance Support*	Foundational	Foundational level of maturity in resource planning and acquisition for responding to large-scale emergencies. Logistics is specifically defined in the LGU entities' ICS structure. However, it is unclear if resource planning and acquisition is tested in emergency drills. Additionally, supporting systems for crew rosters and logging gas mutual assistance were not mentioned. Severe winter weather damage prediction models for gas distribution were not specifically indicated for the LGUs
Indicator 4 – *Asset Management and Inspections*	Leading	Leading level of maturity in asset management practices and asset inspections to assure that critical infrastructure will properly operate during adverse weather events. The LGUs demonstrated completing condition assessments for severe winter weather during periodic regulator station, main, and services inspections. The LGU have completed some mitigation actions in regulator stations such as adding heaters and heat trace wire. However, formal programs for severe winter weather are not indicated. Additionally, specific budgets for severe winter weather programs have not been established.
Indicator 5 – *Operational Protocols*	Leading	Leading level of maturity in implementing adverse weather operational protocols. Through periodic inspections and patrols, annual maintenance, and monitoring through gas SCADA, the LGU entities identify and correct any conditions that would increase vulnerability to extreme cold. While the LGUs complete periodic inspections and annual maintenance that assess vulnerability to extreme cold and monitor pipeline and regulator conditions through gas SCADA, they are not substitutes for proactive operating procedures that assess conditions prior to a predicted cost weather emergency event.
Indicator 6 – *System Design and Hardening*	Leading	Leading level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers. LGU entities demonstrated adequate processes that assure the design standards consider protection of facilities to cold winter weather events. Examples include installation of additional heaters at regulator stations, protection of sensing lines, physical barricades and fences, and other physical security improvements.
Indicator 7 – *Stakeholder Engagement*	Leading	Leading level of maturity in accurately communicating and developing a utility's resilience strategies and plans with their stakeholders. The LGU entities understand their stakeholders as documented in their list as maintained by an assigned team in their organizations. Their communication plan is intended during (and in proximity) of the event only use of technology is adequately documented by tagging customers for restoration priority in their Customer Information Systems.

Indicator	Maturity	Preliminary Key Findings
Indicator 8 – *Public Communications*	Leading	Leading level of maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards. They indicated having a comprehensive database of state and local government officials for the purpose of communicating in advance, during, and after a severe weather event.
Indicator 9 – *Automation*	**Not rated**	Not evaluated for natural gas utilities – not applicable for smart grid technologies.
Indicator 10 – *Situational Awareness*	Foundational	Foundational level of maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events. They have demonstrated basic use of a damage prediction models and they continue to investigate the feasibility of a more comprehensive severe weather damage prediction models.
Indicator 11 – *Compliance to Regulations*	Leading	Leading level of maturity in adhering to federal, state, or local reliability and resilience requirements. The LGUs provide specific references that assure compliance with these various regulations. The DIMPs and TIMPs developed by the LGU are comprehensive and well-devised.

Overall, the SEU entities are adequately mature in their ability to withstand potential ice storms and other winter weather events. In this overall rating, the SEUs are on the low end of the spectrum and there are numerous opportunities for improvement. **Table 12** summarizes the preliminary key findings for Small Electric Utilities.

Table 12 – Preliminary Key Findings - Small Electric Utilities

Indicator	Maturity	Preliminary Key Findings
Indicator 1 – *Emergency Management and Planning*	Foundational	Foundational level of maturity in emergency management planning and preparation. The level of detail and specific information provided by the SEUs and their support organizations varied significantly. The resulting assessment ratings reflect an average value for the SEUs collectively while individual assessments may be higher or lower than the group. Mutual assistance arrangements are well-defined for the SEUs. Most SEU entities mentioned monitoring a number of weather services during incoming storm events. Not all SEUs appear to use ice storm prediction tools. They should investigate additional technology to assist with providing better ice storm damage predictions and to help manage resources during the restoration process more efficiently.
Indicator 2 – *Risk Management*	Foundational	Foundational level of maturity in developing infrastructure risk management. [Additional supporting details to be provided in Final Report.]
Indicator 3 – *Staffing and Mutual Assistance Support*	Foundational	Foundational level of maturity in resource planning and acquisition for responding to large-scale emergencies. All SEU entities reported using mutual assistance as a part of their overall emergency restoration plans. ECSC and SCAMPS provide coordination services for their members to access additional resources during emergency events.

Indicator	Maturity	Preliminary Key Findings
Indicator 4 – *Asset Management and Inspections*	Lagging	Lagging level of maturity in asset management practices and asset inspections to assure that critical infrastructure will properly operate during adverse weather events. SEU entities all perform various types of traditional, calendar-based inspection programs including pole inspections and replacement, visual line patrols, infrared switches, substation relay testing, transformer oil sampling, and inspections. None mentioned using any formal asset management software or non-calendar-based approaches. Several utilities reporting using their GIS to store inspection records.
Indicator 5 – *Operational Protocols*	Foundational	Foundational level of maturity in implementing adverse weather operational protocols. Several utilities presented cold weather checklists and mentioned procedures to prepare for incoming storms, but no specific operating procedures for cold weather events were identified.
Indicator 6 – *System Design and Hardening*	Lagging	Lagging level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers. The National Electrical Safety Code (NESC) Medium Loading for design criteria with Grade C and Grade B construction levels are being followed by the utilities, which is appropriate for South Carolina. Some SEUs reported going 'above and beyond' these construction specifications occasional where warranted. Consideration should be given to adopt Grade B, the 'studier' level of construction, as the standard for line construction. All SEUs mentioned following standard vegetation management (e.g., tree trimming) practices, with one mentioning a specific trimming strategy so ice-laden trees fall away from the power lines.
Indicator 7 – *Stakeholder Engagement*	Lagging	Lagging level of maturity in accurately communicating and developing a utility's resilience strategies and plans with their stakeholders. [Additional supporting details to be provided in final report.]
Indicator 8 – *Public Communications*	Lagging	Lagging level of maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards. [Additional supporting details to be provided in final report.]
Indicator 9 – *Automation*	Lagging	Lagging level of maturity in the use of automation and information available from the deployment of smart grid technologies. [Additional supporting details to be provided in final report.]
Indicator 10 – *Situational Awareness*	Lagging	Lagging level of maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events. [Additional supporting details to be provided in final report.]
Indicator 11 – *Compliance to Regulations*	Foundational	Foundational level of maturity in adhering to federal, state, or local reliability and resilience requirements. [Additional supporting details to be provided in final report.]

Overall, the SGU entities are adequately mature in their ability to withstand potential ice storms and other winter weather events. **Table 13** summarizes the preliminary key findings for Small Natural Gas Utilities. A Maturity level marked *Not Rated* reflects an indicator maturity score that has not been calculated due to insufficient data received by Utility Providers as of August 31, 2021.

Table 13 – Preliminary Key Findings - Small Natural Gas Utilities

Indicator	Maturity	Preliminary Key Findings
Indicator 1 – *Emergency Management and Planning*	Not Rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's processes in emergency management planning and preparation. No matter the size of the entity, emergency preparedness is needed for gas utilities which provide an essential service to communities, business, and industry. It is recognized that SGUs may not have the resources to implement the ICS. However, a basic emergency plan which defines roles and responsibilities, identifies external agencies, and specifies emergency role training and emergency drills and/or tabletop exercises is highly recommended. Since many of the are members of the Carolinas Public Gas Association (CPGA), perhaps a joint effort would provide consistency and efficiencies.
Indicator 2 – *Risk Management*	Foundational	Foundational level of maturity in developing infrastructure risk management. SGU entities are expected to have more than adequate risk management processes because they systematically evaluate risks and threats through DIMPs and TIMPs which are required per regulation of the US DOT's PHMSA. The regulations require operators, such as LDCs, to develop and implement written integrity management programs addressing the following elements: (a) knowledge of infrastructure, (b) identification of threats, (c) evaluation and prioritization of risks, (d) mitigation of risks, (e) measurement and monitoring of performance, (f) periodic evaluation and improvement, and (g) reporting of threats. Within the DIMPs, the SGUs generally rated natural forces severe winter weather risk as extremely low. The extremely low risk was due to a lack of damage to gas infrastructure due to no prior history of damage to gas infrastructure. The responding entities have no specific programs for severe winter weather risk mitigation.
Indicator 3 – *Staffing and Mutual Assistance Support*	Not Rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's processes with regards to resource planning and acquisition for responding to large-scale emergencies. The SGUs did not provide responses to the DRs related to staffing and mutual assistance support.

Indicator	Maturity	Preliminary Key Findings
Indicator 4 – *Asset Management and Inspections*	Not Rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's asset management practices and asset inspections to assure that critical infrastructure will properly operate during adverse weather events The SGUs did not provide responses to the DRs related to asset management and inspections.
Indicator 5 – *Operational Protocols*	Not Rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's capability in implementing adverse weather operational protocols. Operating protocols commonly take the form of written and published operating procedures that are reviewed annually with employees. The SGUs did not provide responses to the DRs related to operational protocols.
Indicator 6 – *System Design and Hardening*	Lagging	Lagging level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers. None of the respondents provided a CAPEX budget for gas severe weather resiliency investments or details regarding gas system severe weather hardening programs. Some of the respondents claimed that the budgets for gas system reinforcement includes winter weather resilience but could not provide clear substantiation. None of the respondents provided natural gas engineering standards related to the protection of sensing lines and regulators in natural gas regulator stations and purchase points.
Indicator 7 – *Stakeholder Engagement*	Not rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's maturity and capability to accurately communicate and develop their resilience strategies and plans with their stakeholders. The SGUs did not provide responses to the DRs related to stakeholder engagement.
Indicator 8 – *Public Communications*	Not rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards. The SGUs did not provide responses to the DRs related to stakeholder engagement and consequent public communications.
Indicator 9 – *Automation*	N/A	Not evaluated for natural gas utilities – not applicable for smart grid technologies.

Indicator	Maturity	Preliminary Key Findings
Indicator 10 – *Situational Awareness*	Not Rated	From an overall assessment perspective, this indicator was not scored due to insufficient data received. The level of maturity was not calculated for the SGU's maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events. The SGUs did not provide responses to the DRs related to situational awareness.
Indicator 11 – *Compliance to Regulations*	Foundational	Foundational level of maturity in adhering to federal, state, or local reliability and resilience requirements. Most of the respondents provided a DIMP or TIMP. The plans were comprehensive. Although not specifically required in the initial data request, Patriots Energy Group provided detailed information on gas supply and peak data requirements at interconnection stations. It is highly recommended that each gas agency submit information related to determination of the peak design day and the ability to meet this demand during a severe winter weather event.

[Final Report will include a table of final recommendations by utility category.]

8 Additional Findings

[The contents in this section will be included in the Final Report after all of the remaining information request responses are reviewed and evaluated.]

8.1 Threats to and Vulnerabilities

[Final report will include a description of state-wide threats/vulnerabilities; this sub section will not be present in the Draft Report]

8.2 Resiliency Requirements and Standards

[Final report will include a characterization of the type of standards and requirements observed by utility providers and potential others that might be considered; this sub section will not be present in the Draft Report]

8.3 Resiliency Solutions (Planned and In Place)

[Final report may include a description of other resiliency solutions planned or in place (based on the review of the second round of discovery responses); this sub section will not be present in the Draft Report]

8.4 Gaps and Opportunities

[Final will include overall gaps and opportunities for the State (based on the review of the second round of discovery responses); this sub section will not be present in the Draft Report]

8.5 Risks and Potential Impacts

[Final report will include overall risks and potential impacts to the State (based on the review of the second round of discovery responses); this sub section will not be present in the Draft Report]

9 Final Recommendations

[Final Overall Recommendations to be included in the final report.]

Appendix A. Assessment Framework Evaluation Areas

Table A-1 and **Table A-2** describe the five (5) categories for each of the assessment indicators.

Table A-1 – Categories for Each of the Assessment Indicators Areas (Categories 1 and 2)

	PEOPLE/CULTURE	GOVERNANCE
Indicator 1 – Emergency Management and Planning	Employees are fully trained and understand their emergency management role.	A formal emergency management governing body is established with clearly defined roles and responsibilities.
Indicator 2 – Risk Management	Identification and mitigation of risks to critical assets and infrastructure is a strategic priority.	Risk management governance enables identification of risks to critical infrastructure.
Indicator 3 – Staffing and Mutual Assistance Support	Employees proactively participate in well-coordinated advanced resource planning and acquisition for major emergencies.	A centralized governance structure has been established to estimate and acquire resources and assets in preparation for major weather events.
Indicator 4 – Asset Management and Inspections	Management identifies and prioritizes asset and non-asset solutions with consideration of financial viability, social and environmental responsibility, and cultural outcomes.	Objectives for asset management are identified, and asset performance is measured.
Indicator 5 – Operational Protocols	Employees are aware and fully trained on operational protocols and their specific roles and responsibilities during adverse weather events.	A governance structure for operational protocols enhances communication, coordination, and operational effectiveness for response to adverse weather conditions.
Indicator 6 – System Design and Hardening	Management understands the benefits of resilience investments and evaluates costs and benefits to prioritize and make investment decisions.	Investment planning governance processes assure that the benefits and cost of resilience solutions are evaluated on a common scale.
Indicator 7 – Stakeholder Engagement	Utility leadership and employees seek to form a partnership with a diverse set of stakeholders.	Stakeholder engagement for adverse weather events is governed and coordinated at a corporate level.
Indicator 8 – Public Communications	Utility leadership seeks to broaden communications, transparency, and accountability across the industry.	Governance is established to assure communications are consistent, understandable, and meaningful.
Indicator 9 – Automation	Utility leadership seeks to broaden communications, transparency, and accountability across the industry.	Governance is established to support automation functionalities and utilization of detailed.
Indicator 10 – Situational Awareness	Utility Leadership seeks to broaden communications, transparency, and accountability across the industry.	Governance protocols are established to assure full utilization of situational awareness capabilities.
Indicator 11 – Regulatory Compliance	A culture of compliance and ethics and assures that actions are taken to address identified high priority threats, impacts and vulnerabilities.	Governance is established to assure that an effective compliance framework is executed on an on-going basis.

	PROCESS	SYSTEMS/TECH	DATA/ANALYTICS
Indicator 1 – Emergency Management and Planning	Well-defined and efficient ICS processes have fully implemented and enable high effective emergency management.	Systems and tools are in place that streamline management and reporting during major weather events.	Complex analytical approaches are used to model and predict damage and is leveraged in pre-event mobilization.
Indicator 2 – Risk Management	Methods and frameworks are in place to manage asset risks within the enterprise portfolio.	Integrated systems and tools are used to manage resilience risks and the status of mitigation actions.	Risks are quantified through data and advanced analytics.
Indicator 3 – Staffing and Mutual Assistance Support	Established processes are enacted during mobilization for adverse weather events.	Defined tools and systems are used to plan and acquire resources and assets in preparation for adverse weather events.	Accurate estimates based on history and weather projections enable timely and proactive resource planning and acquisition.
Indicator 4 – Asset Management and Inspections	Defined processes are implemented and followed to optimize asset inspections and timely maintenance and repairs.	Enterprise wide integrated asset management system with asset performance management enables investment planning and decision-making.	Asset data is foundational for enabling asset management functions. Planning for asset renewal and maintenance activities proceeds with full knowledge of asset location, condition, and operation.
Indicator 5 – Operational Protocols	Defined operational protocol practices and processes are established to assure effective and timely response to adverse weather events.	Tools and technology required to support execution and tracking of operational protocols supports strong governance and defined processes.	Process and user-related data are used to gauge the effectiveness of operational protocols and associated processes.
Indicator 6 – System Design and Hardening	T&D design and hardening standards are developed to provide adaptation for severe weather events and climate impacts.	An investment portfolio management system is deployed to evaluate resilience on a common economic scale.	Advanced analytical approached are used to determine the most cost-effective resilience measures.
Indicator 7 – Stakeholder Engagement	Processes and roles and responsibilities must be defined to enable meaningful stakeholder engagement.	Online engagement platforms used to educate and gather stakeholder and customer feedback supports informed decision-making.	Gathering detailed stakeholder input is crucial to understanding and ultimately influencing changes to processes, mitigation, and strategy.
Indicator 8 – Public Communications	Processes have been defined to openly gather and share information with key internal and external stakeholders.	A wide variety of communications channels and approaches are used to increase reach to various stakeholder groups.	Data is gathered from internal and external sources and specific targets set for communication effectiveness.
Indicator 9 – Automation	Streamlined processes have been developed to assure the maximum value has been derived	Self-healing operations and autonomic computing and machine learning will	Data is gathered and captured in a common data lake for advanced analytics.

	from automation investments.	provide leading grid edge stability.	
Indicator 10 – Situational Awareness	Processes assure situational awareness is deployed during all phases of severe weather response.	Systems and technology provide advanced capabilities for near-time situational awareness.	Analytics provide information to accurately predict impacts and response to severe weather events.
Indicator 11 – Regulatory Compliance	A culture of compliance and ethics assures that actions are taken to address identified high priority threats, impacts, and vulnerabilities.	Governance is established to assure that an effective compliance framework is executed on an ongoing basis.	

Appendix B. **Extreme Weather Leading Practices**

[Section to be included in Final Report]

Appendix C. **Regional Examples and Practices**

[Section to be included in Final Report]

Appendix D. Notable Preliminary Findings

[This content below is in DRAFT form, based on the initial information submitted by utility providers and does not reflect additional information submitted by utility providers after August 31, 2021. In the Final Report, this section will be revised based on the resolution of initial findings, identification of additional findings, and development of additional recommendations by the Evaluators.]

Indicator 1 – Emergency Management and Planning

Highlighted Preliminary Findings and Recommendations

For LEUs

- The Incident Command System (ICS) structure has been fully integrated into the LEU entities' enterprise culture.
- Emergency management teams are trained specific to their roles. Personnel training programs are the fully tracked. Personnel competency on the business continuity plan is part of the entities' personnel training programs.

For LGUs

- The ICS structure or equivalent has been fully integrated into the LGU entities' enterprise culture. By using the ICS structure, the entities demonstrate the use of a standardized approach to the command, control, and coordination of emergency response, providing a common hierarchy within which responders from multiple agencies can be effectively managed before, during, and after a major event.
- LGUs should consider severe weather emergency drills that include the participation of state and local emergency management agencies.
- LGUs should consider inviting outside third parties (as independent observers) to review and provide comments on their emergency plans.

For SEUs

- The level of detail and specific information provided by the SEUs and their support organizations varied significantly. The resulting assessment ratings reflect an average value for the SEUs collectively while individual assessments may be higher or lower than the group.
- Mutual assistance arrangements are well-defined for SEU members.
- Most SEU entities mentioned monitoring a number of weather services during incoming storm events.
- Most SEUs provided evidence of an ERP. SEUs should ensure a minimally detailed emergency restoration plan, including communications plans and backup contingency plans for critical facilities and infrastructure, are documented, employees are trained, and the plan is exercised at least once a year.
- Not all SEUs appear to use ice storm prediction tools. They should investigate additional technology to assist with providing better ice storm damage predictions and to help manage resources during the restoration process more efficiently.

Indicator 2 – Risk Management

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities adequately described the various processes and procedures they use to assess and evaluate winter weather threats and risks to safe and reliable electric and natural gas service, as applicable.
- LEU entities have demonstrated their capability to use the historical experience of their assets to improve their risk management process.
- LEU entities have well-documented storm plans that identify potential risks that may impact the system.
- The use of technology and tools to enhance the risk management process increase the awareness for the entity's emergency management organizations.
- The use of analytics is not prevalent, but there are examples worth noting for reference.

For SEUs

- Other than the United States Department of Agriculture Rural Utility Service (USDA RUS) bulletin, no SEU provided documentation around requirements or guidelines to conduct a vulnerability and risk assessment (VRA). It is not clear to what extent all the SEU entities conducted a formal VRA on their system for extreme cold weather events or any outage event.

Indicator 3 – Staffing and Mutual Assistance Support

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities have established arrangements for mutual aid.
- Various programs were created to formalize agreements between entities to prepare for major events, most of which addresses supply chain issues.

For SEUs

- All SEU entities reported using mutual assistance as a part of their overall emergency restoration plans (ERP).
- ECSC and SCAMPS provide coordination services for their members to access additional resources during emergency events.

For SGUs

- All SGUs should include a comprehensive list of severe winter weather risks in the next update to their Distribution Integrity Management Programs (DIMPs) and Transmission Integrity Management Programs (TIMPs).

Indicator 4 – Asset Management and Inspections

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities provided sufficient documentation depicting their asset management and inspection programs. They conduct periodic condition assessments for major systems and equipment to ensure safe and efficient operations.
- LEU entities use internal lessons learned (following outages and major events) to continuously improve on their preparation and response to extreme weather events.
- The use of technology and tools to enhance asset management is a prevalent practice.

For SEUs

- SEU entities all perform various types of traditional, calendar-based inspection programs including pole inspections and replacement, visual line patrols, infrared switched, substation relay testing, transformer oil sampling, and inspections.
- No SEU mentioned using any formal asset management software or non-calendar-based approach. Several utilities reported using their GIS to store inspection records.

Indicator 5 – Operational Protocols

Highlighted Preliminary Findings and Recommendations

For LEUs

- Operating procedures appear to be robust as reported by the LEU entities.

For SEUs

- Several utilities presented cold weather checklists and mentioned procedures to prepare for incoming storms, but no specific operating procedures for cold weather events were identified.

Indicator 6 – System Design and Hardening

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities demonstrated adequate processes to keep up with current standards and have invested in resiliency as necessary (based on the information in the capital plans they provided).
- Adequate documentation was provided that depicted the overall approach to how entities' respective planning organizations perform the annual transmission system assessments.
- Entities appropriately described their distribution planning standards and their loading criteria.

- All LEU entities are adequately addressing winter storm events. They provided documentation that showed their transmission long-term planning criteria, which is consistent with NERC and other industry planning standards.

For SEUs

- The NESC Medium Loading design criteria is being followed by the utilities, which is appropriate for South Carolina.
- All utilities mentioned following standard vegetation management (e.g., tree trimming) practices, with one mentioning a specific trimming strategy so ice-laden trees fall away from the power lines.
- The use of distribution automation (DA) devices varied greatly across the SEUs. Most reported have some level of Supervisory Control and Data Acquisition (SCADA) installed in some substations and most reported having Advanced Metering Infrastructure (AMI) in place. For more advanced distribution automation, the responses varied from reporting that they use no automation to having a very robust DA program. SEUs should engage vendors to evaluate material specification around withstanding cold weather and extreme ice conditions.
- Not all SEUs tracked outage restoration metrics. These metrics should be tracked to help identify problem areas on the system where grid hardening may be beneficial.

Indicator 7 – Stakeholder Engagement

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities have solid processes to identify their critical facilities and customers and designed a process to communicate and interact with key stakeholders.
- Critical facility identification and prioritization is not widely practiced. This is an improvement opportunity.

For SEUs

- While the SEU entities will have contact with customers and local, state, and federal emergency management entities during a storm, little information was provided regarding the level of engagement the SEU entities take to solicit input and educate stakeholders on their resiliency plans.

Indicator 8 – Public Communications

Highlighted Preliminary Findings and Recommendations:

For LEUs

- LEU entities are consistent in incorporating technology into their communication plans.

For SEUs

- Most SEU entities have a formal communications protocol for who is responsible for external communications during an extreme weather event and use traditional channels such as TV, radio, and newspapers as well as social media, internet, and texting.
- No information was provided pertaining to SEU entities' efforts to communicate with the public about their emergency response or resiliency plans on an ongoing basis.

Indicator 9 – Automation

Highlighted Preliminary Findings and Recommendations

For LEUs

- Little information was provided on DA.
- LEU entities demonstrate a prevalent use of their GIS to automate the dissemination of information for severe weather planning and operations.
- LEU entities generally take advantage of technology to automate (where possible) key processes in assisting their damage assessment.

For SEUs

- Several SEUs mention the use of SCADA but did not describe the extent of the deployment or how it might be integrated into the outage management system (OMS).
- The use of DA devices varied greatly across the SEUs. Most reported have some level of SCADA installed in some substations and most reported having AMI in place. For more advanced distribution automation, the responses varied from reporting that they use no automation to having a very robust DA program.

Indicator 10 – Situational Awareness

Highlighted Preliminary Findings and Recommendations

For LEUs

- LEU entities reported having the foundational tools and processes for situational awareness.

For SEUs

- Most SEU entities mentioned using several weather services that provide information and analysis regarding pending weather events, including cold weather.
- Several SEU entities mentioned reported having SCADA and AMI deployed extensively on their grids.

For SGUs

- SGUs should consider developing situational awareness plans and protocols for gas-adverse weather readiness.

Indicator 11 – Regulatory Compliance

Highlighted Preliminary Findings and Recommendations:

For LEUs

- LEU entities are subject to extensive regulatory oversight by the state and federal government through various regulatory agencies. The entities have demonstrated via specific references to federal and state laws the adequacy and quality of service and their internal practices.
- Transmission operations and planning appears to be in compliance with applicable NERC reliability standards and guidelines.
- Readiness plans are coordinated with VACAR utilities.
- In conformance with NERC reliability standards, readiness plans have been established to address short- and long-term transmission upgrades to ensure no loading or voltage violations for system contingencies.

For SEUs

- ECSC members are required to provide certain documentation regarding policies and procedures (e.g., emergency response plans and vulnerability assessments) to receive funding from the USDA RUS. All cooperatives were reported as being in compliance with these.
- SCAMPS members that are municipalities are a part of city government and do not have any reliability compliance requirements with local, state, or federal governments.